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NSON-DK energy system scenarios – Edition 2

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Title: NSON-DK energy system scenarios – Edition 2

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Summary:

This report describes the energy system scenarios developed in the NSON-DK project, with focus on the future massive offshore wind power and the associated offshore grid development in the North Sea region. An overall European energy system scenario based on previous research is first described. Then, the important updates and modification applied to it are presented to reach the NSON-DK scenarios towards 2050. The Balmorel energy system model is used to carry out investment optimization for a project-based and an offshore grid scenario. The offshore grid scenario includes integration of offshore wind hubs in the North Sea to the transmission infrastructure connecting the region. Countries in the North Sea region are modelled in detail, while surrounding countries participate in the energy market.

Assumed variable renewable energy (VRE) generation costs are described in detail, with especially solar photovoltaic (PV) and offshore wind power costs expected to decrease significantly towards 2050. The DTU Wind Energy's CorRES tool is used to estimate wind and solar PV capacity factors and model the spatiotemporal dependencies in VRE generation. In addition, costs related to the high-voltage direct current (HVDC) components are modelled and implemented in Balmorel to create a cost model for the North Sea offshore grid.

The capability of Balmorel to model VRE generation and transmission investments simultaneously is used to find optimal shares of different VRE types in the scenarios with different grid structures (project-based vs. offshore grid). The resulting scenarios show that going towards an integrated North Sea grid is expected to increase the overall offshore wind share by 2050. Germany is seen as the country with most hub connected offshore wind, while UK is expected to see most offshore wind installations overall. Denmark is expected to be a significant electricity exporter by 2050, driven by good wind conditions and strong transmission connections to the neighbouring countries.

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Preface

The work presented in this report is deliverable D2.1.Ed2 of the North Sea Offshore Network – Denmark (NSON-DK) project. The report is prepared in collaboration between DTU Wind Energy and DTU Management Engineering.

The NSON-DK project is funded by grant no. 64018-0032 under the EUDP program administrated by the Danish energy Agency (previously under ForskEL). It is carried out as a collaboration between DTU Wind Energy (lead), DTU Management Engineering and Ea Energy Analyses.

Lyngby and Risø, Denmark, 31 October 2018

Matti Koivisto and Juan Gea Bermúdez

Contents

1. Introduction

The NSON-DK project studies how the future massive offshore wind power and the associated offshore grid development will affect the Danish power system in the short, medium and long term. This report describes the energy system scenarios developed in NSON-DK WP2, with focus on the North Sea region and especially on Denmark. The scenarios specify developments towards 2050, with 2030 providing a medium-term view of the future; assumed development by 2020 is taken from external sources.

The developed scenarios provide the basis for the other WPs of the NSON-DK project. When studying, for example, balancing and need for reserves (WP3) or system adequacy (WP4) in the future, information about the expected generation capacities and transmission development are needed. In addition to focusing on Denmark, information about the expected developments in the surrounding countries is needed as modern power systems are highly interconnected; this is especially important in the Danish case with strong connections to other countries.

This report first presents the overall European energy system scenario used as the basis for the NSON-DK scenarios: the Nordic Energy Technology Perspectives 2016 scenario. The scenario foresees a significant CO_2 price increase beyond 80 €/ton after 2030 and towards 136 €/ton by 2050. However, some important updates and modifications to the scenario were required, e.g., considering the rapidly decreasing costs of wind and solar power. A major part of this report is to explain these updates and how they are implemented in the energy system modelling.

Considering the decommissioning of fossil power plants and increasing CO_2 price, the amount of variable renewable energy (VRE) generation is expected to increase significantly in the future. The NSON-DK scenarios describe how much of the VRE generation increase is expected to be onshore wind, offshore wind and solar photovoltaic (PV) in the different studied scenarios, utilising updated cost estimates and assumptions about investable VRE generation capacities in the different countries until 2050. Possible limitations on how much onshore wind can be installed in the future are also considered. The VRE generation modeling is carried out using the DTU Wind Energy's CorRES tool. The investment optimization is carried out with the Balmorel energy system model.

Combined with the VRE generation development, transmission capacity expansion is also optimized. This allows, for example, increased connection of flexible Norwegian hydro generation to the other countries, which can support VRE development. Crucially for the NSON-DK project, the scenarios include modelling of a North Sea offshore grid. The offshore grid scenario allows both increased transmission capacity between countries and integration of offshore wind power via hubs. Alongside with the offshore grid scenario, a more traditional project-based scenario is modelled; it includes otherwise the same assumptions and input data, but the integrated offshore grid structure is not included in the system optimisation. Comparison of the project-based and offshore grid scenario allows assessing the effects of an offshore grid on North Sea energy system development.

2. Overview of the NSON-DK scenarios

This chapter presents an overview of the scenarios studied in the NSON-DK project. Then, the European energy system scenario used as the background for the NSON-DK scenarios, and the modifications done to it, are introduced. The detailed implementations of the modifications are presented in later chapters.

2.1 The studied scenarios

This section outlines the scenarios modelled in the NSON-DK project. First, the geographical region in focus is presented. Then, the structures of the analysed scenarios are explained. The structures determine the overall boundaries of the scenarios and differentiate them from each other. The modelling of the scenarios is explained later in Chapter 3.

2.1.1 Countries in focus

The NSON-DK project focuses on the North Sea region. Countries analysed in detail are: Denmark (DK), Norway (NO), United Kingdom (UK), Netherlands (NL), Belgium (BE) and Germany (DE). For UK, the energy system of Great Britain (GB) is modelled, so the numbers refer to GB. The countries are shown on map in Figure 1. Even though Denmark is the main focus in the NSON-DK project, the other countries are important when analysing the overall development of the North Sea region, especially when considering the North Sea offshore grid.

However, it is not sufficient to focus solely on the mentioned North Sea countries, as electricity is traded between countries. Thus, important surrounding countries were also included in the energy system modelling: they take part in the energy market, but are not included in the investment optimization; however, they do experience an assumed future energy system development as described in Section 2.2. The countries participating in the energy market, in addition to the countries mentioned above, are: Sweden, Finland, Estonia, Latvia and Lithuania (to include all of Nord Pool), and France and Poland.

Figure 1: The countries analysed in detail in the NSON-DK scenarios are highlighted in the map.

2.1.2 Project-based and offshore grid scenario

A project-based and an offshore grid scenario is developed in the NSON-DK project. These scenarios are differentiated by the allowed offshore grid structure, as shown in Figure 2: The offshore grid has more options in the investment optimization. Including radial connections as possibilities also in the offshore grid scenario creates a competition of radial connections and an integrated solution. This was considered desirable, as the offshore grid is not simply forced on the system, but appears only if it is favourable in the investment optimization.

Optimisation of an offshore grid, with a lot of possible hubs and connections between the hubs and to shore, is computationally significantly more complex than optimising a project-based (radial) scenario; this is described in section 3.2. The two scenarios are presented and compared in Chapter 6.

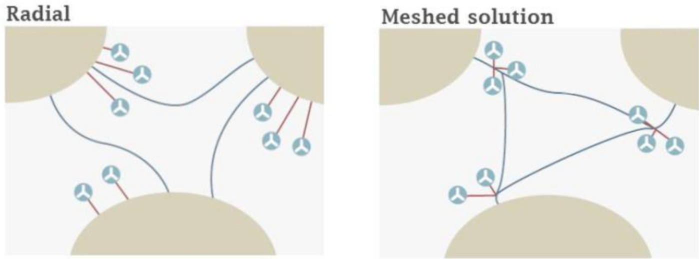

Figure 2: Schematic view of project-based ("radial") and offshore grid ("meshed") connection structures [1]. In the project based NSON-DK scenario, only the "radial" type of connections are allowed; in the offshore grid scenario, both "radial" and "meshed" connections are allowed.

2.1.3 Possible limitations on future onshore wind installations

The investable capacities of different VRE generation types in the different countries are presented in section 5.2. For onshore wind, the source for potentials by 2050 is [2]. However, it was considered that these numbers may be somewhat high, e.g., for UK (38.4 GW), as building significantly more onshore wind can be challenging, for example, because of social and political opposition. Thus, both the project-based and the offshore grid scenario were modelled with high and low onshore wind capacity assumptions to investigate VRE capacity development if onshore wind investments are more constrained. The investable onshore wind capacities in the high and low onshore wind cases are presented in section 5.2.3. Comparison of the resulting scenarios is shown in section 6.2.

2.1.4 Other aspects affecting the scenario results

In addition to studying the effects of high and low investable onshore wind capacities on the scenarios, two additional studies are carried out. These consider impact of intertemporal optimisation and transmission line cost assumptions. The transmission line costs are studied by simply comparing expected technical line costs, as shown in section 4.1.2, to a doubling of these costs; results are presented in section 6.4.

The concept of intertemporal optimisation is presented in section 3.1.2; briefly, it means that expected future development is considered when optimising a scenario year. In the context of NSON-DK scenario modelling, this means that the expectations of 2050 are taken into account when optimising 2030. The scenarios resulting from this approach are compared to the more traditional year-by-year (or myopic) optimisation in section 6.3.

2.2 The NETP 2016 energy system scenario and modifications to it

This section describes the European-wide scenario used as the starting point for the NSON-DK scenarios, and the modifications applied to it. The NSON-DK scenarios are aligned with International Energy Agency's by harmonisation of the input data utilized, which has been obtained from Nordic Energy Technology Perspectives (NETP) 2016 [2], which had 2014 as a base year and was created as an integrated part of Energy Technology Perspectives 2016 [3].

2.2.1 Electricity consumption development

The future development of electricity demand, obtained from [2], is strongly impacted by the assumption of aggressive energy efficiency policies that lead in total to stagnating consumption despite substantial electric vehicle up-take. Hence, efficiency increases in the classical electricity consumption sectors and improvements in the provision of heat from electricity due to the application of heat pumps in combination with improved insolation compensates for the transition towards a larger share of electricity within final consumption. However, as Figure 3 depicts, this general picture does not hold for Denmark.

The NETP 2016 projects a stagnant demand development in total until 2050. By contrast, Denmark is assumed to increase its consumption by 14% from 2020 to 2050. With the exception of Denmark, the

NETP 2016 projection can be regarded as conservative in the sense that scenarios computed by other institutions frequently project some electricity demand increases while reaching climate goals, e.g. the EU reference scenario [4] finds a 19% increase of electricity consumption from 2020 to 2050 in the EU countries neighbouring the North Sea. However, the political targets often foresee stagnant consumption that is compatible with NETP 2016. Moreover, there is no reason why the basic rationale of demand development should have changed since the conduction of NETP 2016.

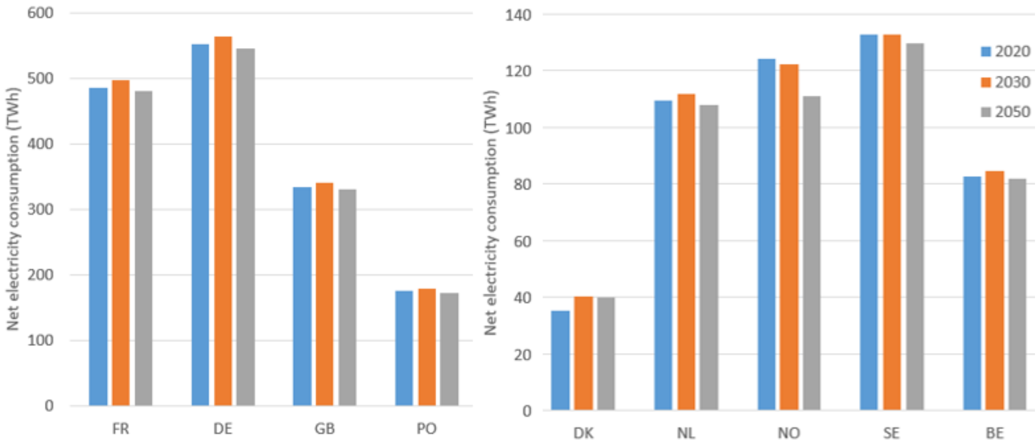

Figure 3: Yearly net electricity consumption development in the North Sea and surrounding countries, taken from [2].

2.2.2 Fuel and emission prices

The fuel and emission price development assumptions, extracted from [2], follow the 2 degree scenario (2DS) and carbon neutral scenario (CNS), respectively. It is apparent from Figure 4 that assumptions from IEA in a 2DS are corresponding to a stagnation of coal price after 2015, and a strong increase of CO_2 prices after 2020 with CNS scenario. Oil and natural gas prices follow similar trends with respect to each other, i.e. from 2015 to 2020 their prices fall slightly, but from 2020 until 2030 they increase to their corresponding 2015 values. Following 2030, fossil fuel prices stagnate while emission prices increase beyond 80 and towards 136 €2015/ton by 2050 (the base year for monetary values is 2015, i.e., €2015).

Figure 4: Fuel and CO_2 price developments used in the NSON-DK scenarios are taken from NETP 2016 [2]. The base year for monetary values is 2015, i.e., €2015.

2.2.3 Analysing countries regionally

To represent the electricity trading between countries and spot market regions, as well as internal congestions, the same split of regions as in [2] has been used for the NSON-DK scenarios. With this, DE is split into four regions, DK in two, NO in five, and the rest have one region per country. Figure 5 illustrates the regions.

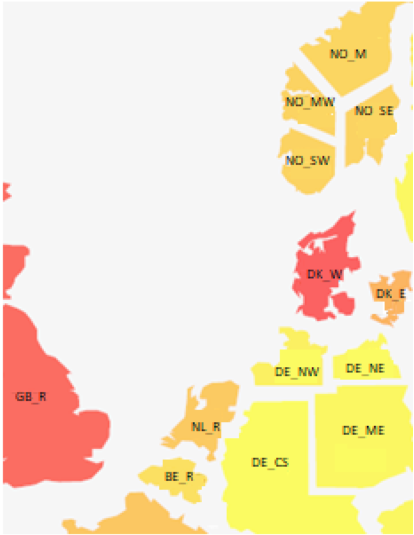

Figure 5: Illustration of the regional split of the countries with investment optimization in the NSON-DK scenarios. NO_N, located in the north of Norway, is not visible on the map (figure taken from [2]).

2.2.4 Transmission grid development

The exogenous transmission grid development for the countries with investment optimization is taken from [2], and depicted in Figure 6. Exogenous means that any transmission investments seen in the NSON-DK scenarios are added on top of these transmission lines. The exogenous development assumes that projected lines such as the Viking Link (DK-UK) and the COBRA line (DK-NL), will be built. Additionally, the assumed development also considers that the current congestion problems that affect DE north to DE south are drastically reduced.

Further transmission development in the countries with investment optimisation is optimized as part of the energy system investment optimization, as described in Chapter 3. Intra-country transmission development is modelled and optimized between the regions shown in Figure 5. For the countries which are not included in the investment optimization, the transmission development towards 2050 is taken entirely from [2].

As the NETP 2016 scenario does not include any offshore grid structure for the North Sea region, all developments related to it are modelled in NSON-DK, as described in the following chapters. However, the lines shown in Figure 5 set the background also for the offshore grid scenario as they set the amount of transmission capacity assumed to be available between the analysed countries and regions as a starting point.

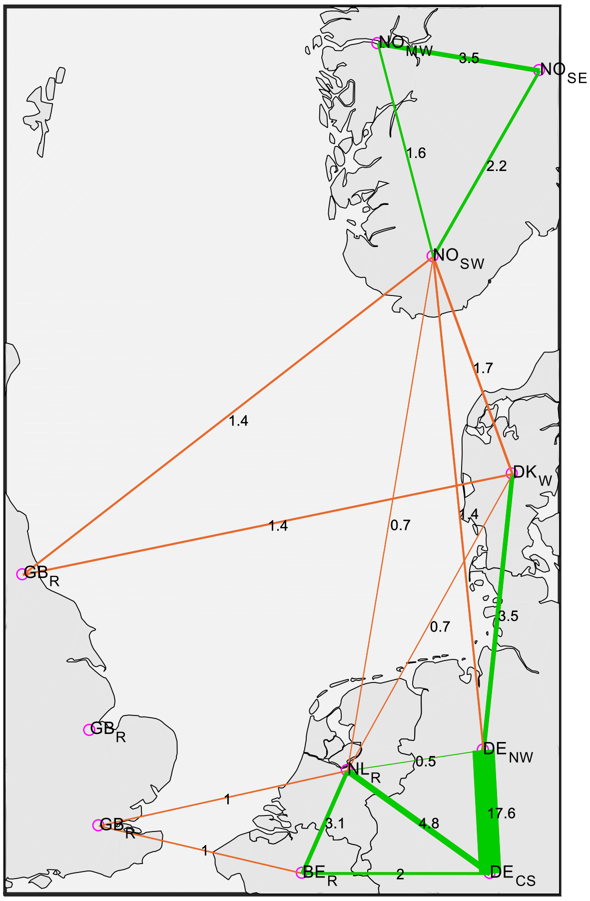

Figure 6: Exogenous transmission development assumed in the NSON-DK scenarios between regions visible in the map (GW). On-land lines are drawn in green and offshore lines in orange.

2.2.5 Development of installed generation capacity

The starting point for modelling the generation capacity development in the countries with investment optimization are the expected installed capacities by 2020, which are shown in Figure 7. The conventional power generation in these countries by 2020 is based on the 2014's capacities from [2] and on decommissioning assumptions, whereas the wind and solar capacities use sources explained in section 5.2.

When optimising the countries, investments are allowed in onshore wind, offshore wind, solar PV, gas turbines burning natural gas, combined cycles burning natural gas, steam turbines burning wood pellets and nuclear thermal power plants (nuclear only in GB). Both transmission and generation are optimized simultaneously in the investment optimization. The generation capacity development until 2050 for the countries without investment optimization is taken entirely from [2].

It is important to clarify that electricity storage capacities and all the heating part of the energy system are not optimized in this project to reduce the complexity of the problem, and their developments along the years analysed in the model are taken directly from [2]. This affects electric batteries, CHP power plants, boilers, heat storages, heat pumps, etc.

Assumptions regarding decommissioning of power generation technologies in the countries with investment optimization have been made to model the expected development of available generation capacities in the future. These assumptions are: all thermal power plants burning fossil fuels working in condensing mode, i.e. producing only electricity, have been decommissioned at a linear rate of 4% with respect to the base year's capacity of [2], which is 2014. For nuclear power, the existing units in the counries with investment optimization have been decommissioned assuming a 50 year lifetime, and the Hinkley Point planned power plant in GB has been added to the exogenous capacities. The results of these assumptions are shown in Figure 8. Decomissioning is not modelled for wind and solar PV.

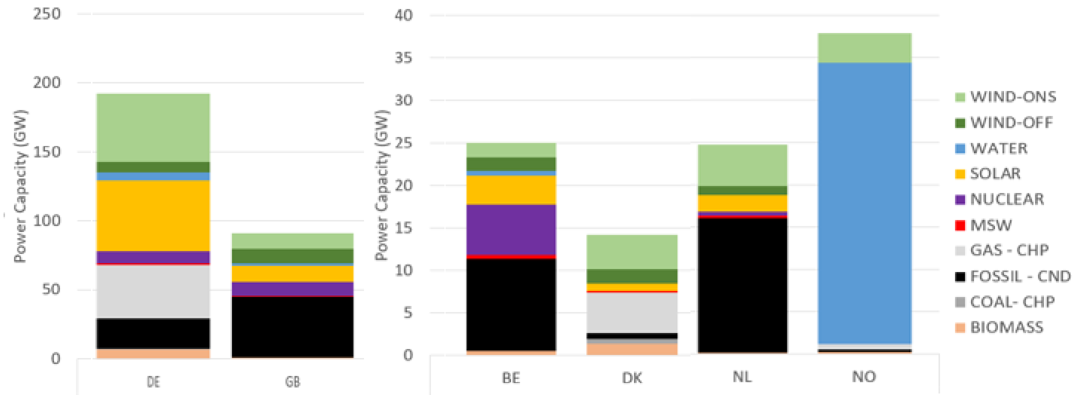

Figure 7: Generation capacities assumed to be installed in 2020 (GW), which is the starting point for the investment optimization modelling in NSON-DK.

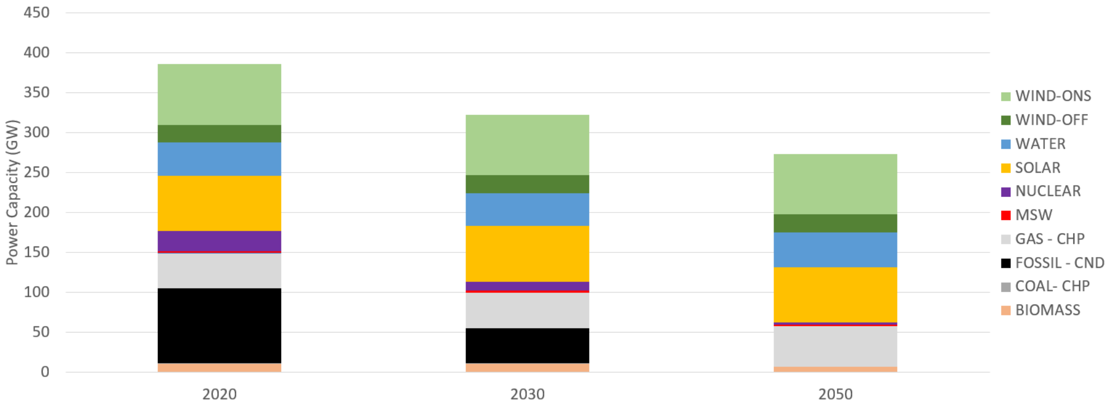

Figure 8. Assumed aggregated exogenous generation capacity development in the countries with investment optimization. This shows the development if no new generation capacity would be invested in the investment optimization towards 2050.

2.2.6 Updating generation and transmission costs

The cost assumptions for the technologies allowed for investments have been updated to the latest sources. This affects considerably the costs of VRE generation compared to what was assumed in [2]. VRE generation types have experienced considerable cost reductions in the recent years, and are expected to decrease even more [5]. The updated cost assumptions are described in Chapter 4.

3. Energy system optimization

This chapter describes the Balmorel energy system model used in scenario modelling, as well as the specific aspects related to NSON-DK scenario analysis. Balmorel is used to carry out investment optimization for the North Sea region in focus, while taking into account also the surrounding countries in energy dispatch.

3.1 The Balmorel model

This section gives a short general description of the Balmorel energy system model. Especially its capabilities in investment optimisation are focused on.

3.1.1 General about Balmorel Energy system modelling

Balmorel is a cost minimization tool that is used to analyse the power and district heat sectors. It is coded in the GAMS language and it is open source. It is a multi-period model with flexible time and area resolution. It has geographical entities representing district heating areas, electricity price regions linked by transmission interconnectors, and countries for representing e.g. taxation and incentive schemes. The production system for electricity and heat includes a number of technologies, including wind, hydro, solar PV and thermal production units and also storage possibilities. The base version of the model is linear, but it has the possibility for introducing integers. Further description of the model can be found in [6].

Balmorel has currently four optimization modes, i.e. BB1, BB2, BB3, and BB4. BB2 and BB4 can be utilized for modelling investments. Among them, the BB4 mode has been selected for investment optimization modelling in the NSON-DK project, and it will be described in the next subsection.

3.1.2 Intertemporal value maximisation

The BB4 mode, in contrast to previous versions, implements intertemporal value maximisation [6]. This allows for intertemporal optimization, which is highly relevant for energy planning. The value of future's years with respect to the first year will depend on the discount rate assumption. Under the assumption of a comparatively low discount rate, this gives rise to solutions that are expected to be closer to a social optimum compared to myopic optimization, i.e., optimizing without taking into consideration what is expected to occur in the future. When higher discount rates are applied, as used in other Balmorel versions and applications to derive more suitable insight for private investment incentives, the value of intertemporal optimization decreases. An example of the importance of this intertemporal optimization is that the model could invest in extra transmission lines in earlier years to be ready to connect future generation investments.

3.2 Investment optimization in NSON-DK scenarios

This section describes some aspects of Balmorel modelling that are especially important in the context of NSON-DK scenarios, relating mostly to the challenges in modelling offshore grid investments.

3.2.1 Introduction of mixed integer programming to the model

When developing a North Sea grid investment model, it was important to take into account that many elements of such offshore grid have important fixed costs. A result where a large number of very small lines are built is likely not cost effective. A simple assumption of constant M€/MW cost (independent of the installed capacity) was considered insufficient due to high fixed cost shares of, e.g., offshore hub investments, as shown in section 4.1. This suggests the use of a nonlinear cost model (in terms of unit cost), based for instance on mixed integer programming (MIP), as used in [7]. For this project, SOS2 variables were introduced in the model to improve the representation of the technologies that are significantly affected by economies of scale: hubs and high-voltage direct current (HVDC) lines.

However, MIP comes with a computational burden that increases the optimisation time. For this reason, when utilizing MIP, the model may require some simplifications to obtain results in a reasonable amount of time. The following subsections explain the simplifications applied in the NSON-DK scenario modelling.

3.2.2 Time step selection

A reduced amount of weeks was used to represent the analysed scenario years, i.e., 2030 and 2050, to be able to obtain results in a reasonable amount of time. When selecting less weeks than the full year in Balmorel, the time series are scaled so the total energy along the year is preserved. So, for instance, if by chance the wind production in the selected weeks was higher than the average of the year, the model will scale the wind generation during the selected weeks down to meet the annual energy generation. The time series were calculated with 2012's weather data, simulating the VRE generation output using 2030 and 2050 technical parameters (they are explained in section 5.2).

After testing the computational time of different amount of weeks, four weeks were found as the most convenient number. To select the four weeks used in the scenarios, the project-based scenario was run with several combinations of eight spread-over-the-year weeks, and the average investment results were considered as a reference. Then, different combinations of four weeks were tested until the results of one the combinations were close to the average eight weeks results. It was also checked that the weeks are spread around the year: one for winter, one for summer, and one for both spring and autumn. The same four weeks were used in the modelling of both the project-based and offshore grid scenario.

3.2.3 Discount and interest rates

A discount rate of 4% was assumed, as used in [5]. This rate controls the importance of future years in the objective function when using intertemporal optimisation, since they will be discounted to the base year's value. Additionally, in order to reflect the risk seen from the private investor for a new investment, we have included an interest rate of 8% for the calculation of the annuities for all the generation technologies, as used in [2], whereas for transmission investments an interest rate of 4% was assumed, since transmission investments are normally state driven.

3.2.4 Drivers for investments

The main drivers for new investments in the model are a) update of technologies, and changing fuel and CO_2 costs in the future, and b) decommissioning of existing units. Depending on the total cost of a technology, which in Balmorel is dependent on their annuity and on their investment, fixed and variable costs, the tool decides which technology is worth investing in [6]. The annuity concept reflects the lifetime, and/or payback time of the loan, and the interest rate of the loan.

4. Cost assumptions

This section describes the costs related to the offshore grid and the VRE generation costs assumed in the NSON-DK scenario modelling. The last section describes other costs, such as onshore transmission line and non-VRE generation costs.

4.1 Cost assumptions regarding the offshore grid

In both the project-based and the offshore grid scenario, there are cost items related to offshore transmission. In the project-based scenario there are only country-to-country (C2C) transmission lines, while the offshore grid scenario includes also hubs, and hub-to-hub and hub-to-shore connections. This section describes the cost parameters for these components.

4.1.1 The HVDC infrastructure cost model

As hub-connected offshore wind power plants (OWPPs) are located close to the hubs, OWPP-to-hub connection is assumed to be high-voltage alternating current (HVAC). However, from the hub onwards all offshore grid infrastructure is assumed to be HVDC. Also, all offshore C2C transmission lines are assumed to be HVDC.

The cost model from [8] is used to estimate all HVDC infrastructure costs. The model

$$C_{\mathrm{est}} = B + N + S, \tag{1}$$

includes three cost components: branch (B), node (N) and additional cost of an offshore node (S) to give the estimated cost C_{est}. Each of these components are further divided to fixed costs, costs per km, etc. Depending on the type of project being analysed, appropriate cost components are considered. For example, for a C2C transmission line, there are no offshore nodes, so $S = 0$. For a radially HVDC connected OWPP, two nodes are needed, but only one of them is offshore, so additional offshore costs are assigned to only one of the nodes.

For the parameters required for (1), the average cost parameter set from [8] is used. The parameters are shown in Table 1. The average parameter set directly specifies the today's costs. However, it was assumed that costs will reduce going towards 2050: the future cost reduction percentage assumed in [5] for OWPP grid connection was applied also for the HVDC cost parameter set. It is important to note that DC breaker costs are not included in the HVDC infrastructure cost model.

An important aspect of the HVDC costs shown in Table 1 are the fixed costs (denoted with "0"). These components mean that the M€/MW costs are not independent of the investment MW size. This means that large investments can be more favourable when considering HVDC components, such as hubs and transmission lines. However, after 2 GW no cost reduction was assumed, i.e., for investments larger than 2 GW, the M€/MW remains on the 2 GW level; a 2 GW limit is used also in [8].

Table 1: Cost parameters for the HVDC infrastructure cost model.

Year	**S_0 (M€)**	**S_p (M€/MW)**	**N_0 (M€)**	**N_p (M€/MW)**	**B_0 (M€)**	**B_l (M€/km)**	**B_{lp} (M€/MW/km)**
Today	44.81	0.0935	28.38	0.08088	0.70	0.68	0.00097
2030	39.52	0.0824	25.03	0.07134	0.62	0.60	0.00086
2050	35.75	0.0746	22.64	0.06453	0.56	0.54	0.00077

The today's cost parameters are taken from the average cost parameter in [8]. For 2030 and 2050, the same learning (i.e., yearly cost reduction in percentage) as in [5] for OWPP grid connection was applied. Costs with "0" refer to fixed cost, "p" refers to costs per MW and "l" refers to cost per km; "S", "N" and "B" refer to the cost components of (1). The costs are in €2015.

4.1.2 Transmission line costs

Transmission line costs between the analysed countries for the 2030 and 2050 scenarios are shown in Figure 9. As for all HVDC items, the M€/MW investments costs are estimated using (1) with the parameters shown in Table 1. The assumed learning (i.e., cost reduction per year) causes the 2050 investments to be cheaper than the 2030 ones. As noted before, the M€/MW costs depend on how large lines are built; Although only costs relating to lines built with 2 GW size are shown in the figure, the MIP modelling in Balmorel considers in detail the effect of building different sized transmission lines (as described in Section 3.2.1).

As was described in section 2.2.3, DK and DE and NO are analysed regionally. NL, BE and GB are analysed as single regions. The costs shown in Figure 9 are estimated by calculating distances from the geographical centres of the regions; expect for GB, which was considered so large region that distance calculation from the geographical centres was not seen appropriate. Intra-country transmission expansion costs were not available for GB to split it to regions. For GB, the distances required for estimating transmission expansion cost are calculated from existing high voltage grid connection points.

In Balmorel modelling, NL and BE can be used to link the large energy systems of UK and DE. Especially for these countries, it was considered appropriate to use the central geographical points of the regions for the basis of calculating the required transmission distances, and thus costs; if distance would have been calculated from some possible grid connection points near the borders of the countries, Balmorel would see the intra-country transmission reinforcements as "free" (i.e., having zero cost).

The C2C lines shown in Figure 9 are available in the investment optimization for both the project-based and offshore grid scenario. However, the North Sea grid is available only in the offshore grid scenario. The hubs that are considered in NSON-DK, and some example connections between them, are shown in Figure 10. The hub locations are based on possible planned locations of future OWPPs, as described in section 5.2. Possible connections from the offshore grid to onshore are to the same onshore connection points as shown in Figure 9 for C2C lines.

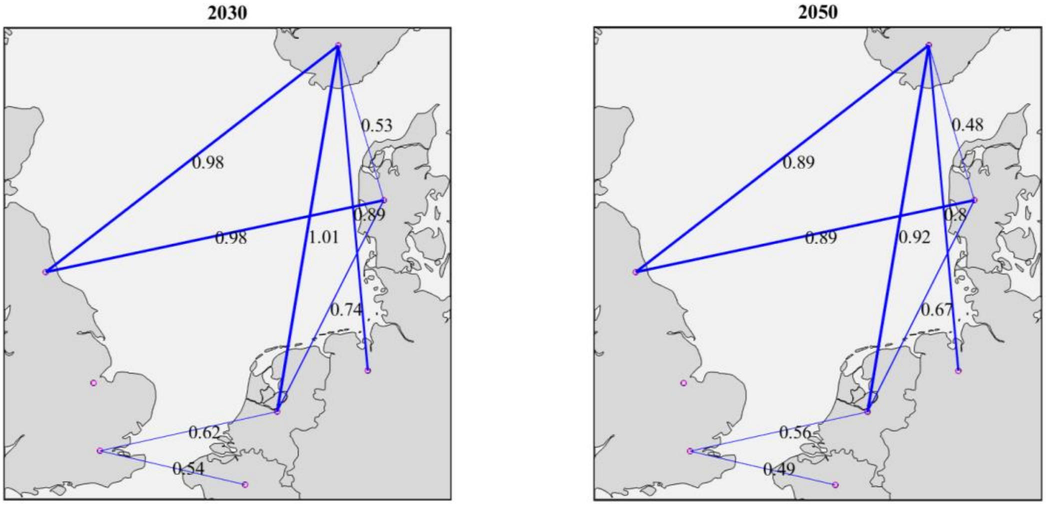

Figure 9. Transmission investment costs (M€/MW) in the 2030 and 2050 scenarios for C2C offshore HVDC lines, assuming they would be built with a capacity of 2 GW. The costs are in €2015.

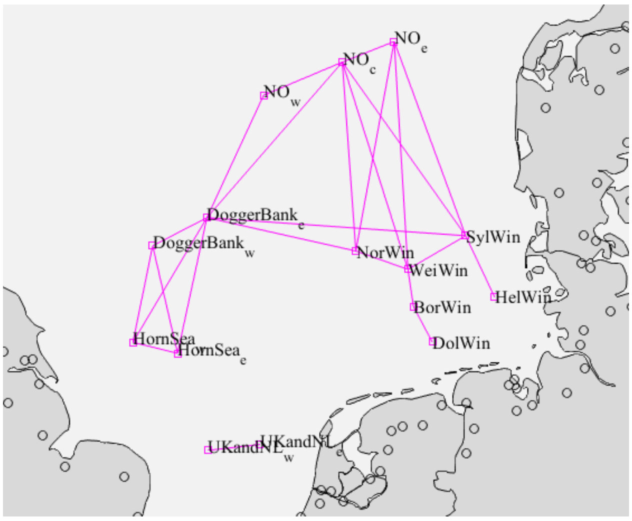

Figure 10: Hubs considered in the offshore grid, with some example connections drawn between them. The investable GWs for the hubs are described in section 5.2.

4.1.3 Hub costs

In the offshore grid investment optimization, hub investments are required for any hub-connected offshore wind to be invested in. A hub consists of one node that is offshore but has no branch, when using (1) to estimate its cost. Resulting hub costs for different hub sizes are shown in Table 2. It can be seen that the M€/MW cost increases about the same when going from 2 GW to 1 GW (Δ = 1 GW), than when going from 1 GW to 0.7 GW (Δ = 0.3 GW); this shows that very small hubs do not seem economically very feasible; the MIP modelling takes this into account in Balmorel.

In addition to building a hub, which is an HVDC component, the actual OWPPs need to be invested in to get generation from hub-connected offshore wind power. These costs are described in section 4.2.

Table 2: Hub investment costs in the offshore grid scenario for some example hub sizes.

Hub size (GW)	If invested in 2030 (M€/MW)	If invested in 2050 (M€/MW)
2	0.19	0.17
1	0.22	0.20
0.7	0.25	0.22

All hubs are assumed to have the same cost (however, connection cost from the hub to onshore varies depending on distance; these differences are included in the line cost components, as described in section 4.1.2). All costs in €2015.

4.2 VRE generation costs

This section presents the costs for the different VRE generation types in the investment optimization. For wind power, the grid connection costs are described in detail as they importantly differentiate the investment costs of the different wind generation types.

4.2.1 Wind power costs (excluding grid connection)

The main source for wind power costs is [5], as it was available in June 2017. The cost numbers used in NSON-DK scenarios are shown in Table 1. The investment and O&M costs, and technical lifetime values are used directly in the investment optimization. The table does not include grid connection costs; they are described in the next subsection. It can be seen that offshore wind is expected to experience significant cost reduction towards 2050 (investment cost around 43 % lower than today); onshore wind is also expected to get cheaper, but with a lower rate (investment cost 23 % lower in 2050 than today).

Wind generation capacity factors (CFs) are modelled separately, as shown in Section 4.3, importantly including the differences in CFs in different countries. The expected developments in wind power technology are aligned with [5], so the expected changes in CFs are in line with the cost shown in Table 3.

Table 3: Wind power costs (excluding grid connection costs)

		Today (2015)	2030	2050
Onshore wind	Investment (M€/MW), excl. grid con.	1.02	0.86	0.79
	Fixed O&M (€/MW/year)	25600	22300	21200
	Variable O&M (€/MWh)	2.8	2.3	2.1
Offshore wind (HVAC or HVDC connected)	Investment (M€/MW), excl. grid con.	2.46	1.64	1.39
	Fixed O&M (€/MW/year)	57300	37800	32100
	Variable O&M (€/MWh)	4.3	2.7	2.2
Nearshore wind	Investment (M€/MW), excl. grid com.	2.21	1.50	1.28
	Fixed O&M (€/MW/year)	51570	34020	28890
	Variable O&M (€/MWh)	3.87	2.43	1.98
All wind	Technical lifetime, all types (years)	25	30	30

All costs are given in €2015.

4.2.2 Wind power grid connection costs

The grid connection costs of wind power investments are modelled in different ways depending on the wind generation type. For onshore wind, a single M€/MW value is given for each scenario year, as can be seen in Table 4 (numbers are taken from [5]).

Offshore wind was split to three different types: nearshore, HVAC connected offshore and HVDC connected offshore. Nearshore OWPPs are less than 10 km from shore, and the split between HVAC and HVDC connected OWPPs was done as shown in Figure 11.

For nearshore and HVAC connected offshore, cost data given in [5] was used to estimate grid connection costs. For nearshore, it was assumed that the shortest distance to shore is taken (as offshore platform is not used), and from that point onwards land cable is used. For HVAC connected offshore wind, shortest distance to the nearest high voltage onshore grid connection point was calculated (connections can be seen in Figure 12). This distance was then split to onshore and offshore parts. Other costs, such as transformer station cost, are taken from [5] for the nearshore ("near shore wind mill" in [5]) and HVAC connected offshore type ("off shore wind mill" in [5]). All grid connection cost components are expected to experience the same percentage-wise cost reduction towards 2050 as the overall grid connection costs given in [5].

For HVDC connected offshore, (1) and the cost parameters shown in Table 1 were used to estimate the grid connection costs. Using the structure of (1), a HVDC connection for an OWPP requires cable ("B"), two nodes ("N") and an extra cost for one of the nodes being offshore ("S"). Cost reductions towards 2050 are as presented in section 4.1.1. It was assumed that a HVAC offshore platform is also required for a HVDC connected OWPP ("offshore platform" cost taken from [5]). Hub-connected OWPPs are also assumed to require a HVAC offshore platform.

As grid connection cable may not follow a completely straight line from an OWPP to the onshore connection point, the estimated direct distances were compared to cable length data available at [21]. A simple regression analysis was carried out for large OWPPs (400 MW or larger) with cable distance data available; it was found out that on average the direct cable length d_{direct} should be modified as

$$d_{\text{actual}} = 1.2 d_{\text{direct}} + 3.6 \text{ km} \tag{2}$$

to get the actual cable length. Large OWPPs were used in this analysis as future development is assumed to consist mainly of large OWPPs.

An overview of the different offshore types is shown in Figure 12 for the project-based scenario. The figure shows all OWPPs that were considered investable by 2050. Although individual OWPPs are analysed, the final investable capacities for Balmorel are given as regional aggregates per offshore type: e.g., nearshore in western DK, or HVAC connected offshore wind in BE. In the offshore grid scenarios, many of the OWPPs shown as HVDC in Figure 12 are considered to be connectable to the offshore grid via hubs, as shown in section 5.2.2. Overview of the grid connection costs of the different offshore wind types is shown in Table 4; more detailed regional numbers are used in Balmorel modelling.

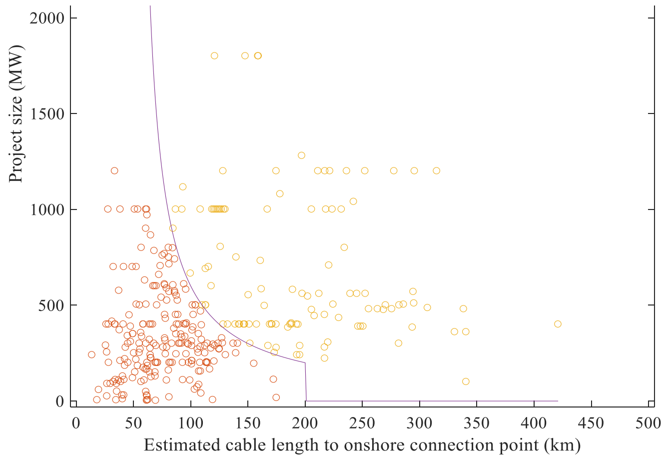

Figure 11: A simple comparison based on estimated cable length to grid connection point and project size was used to split planned future OWPP projects to HVAC (red) and HVDC connected ones (orange).

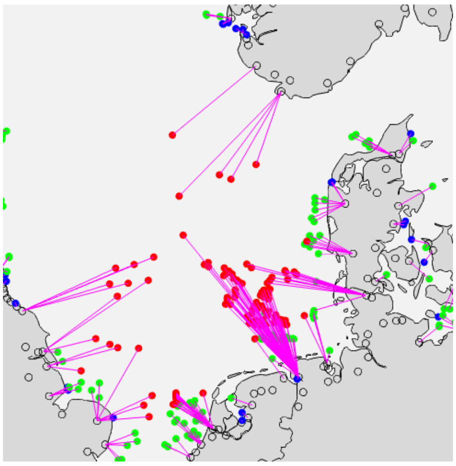

Figure 12: Overview of the OWPPs used to estimate investable offshore wind capacities (based on [21] as it was available in June 2017, with some adjustments). Connection types are estimated for the project-based scenario: blue denotes nearshore, green HVAC connected offshore and red HVDC connected offshore. From these OWPPs, investable offshore capacities are calculated for the Balmorel investment optimization.

Table 4. Wind power grid connection costs

		2030	2050
Onshore wind	Same (M€/MW) for all investments	0.05	0.04
Nearshore wind	Depends on distance; mean of all regions given (M€/MW)	0.23	0.21
Offshore wind (HVAC)	Depends on distance; mean of all regions given (M€/MW)	0.35	0.31
Offshore wind (HVDC)	Depends on distance and installed capacity; mean of all regions given (M€/MW)	0.64	0.58
Hub-connected offshore wind (includes only HVAC connection to hub)	Depends on installed capacity (it is expected that larger hub requires longer HVAC connections, as OWPPs are on average further from the hub); (M€/MW) for 2 GW investment given	0.18	0.16

The given values are for the offshore grid scenario; there are small differences compared to the project-based scenario (because some OWPPs are assigned to a different type group). Cost are in €2015.

4.2.3 Solar PV costs

The source for solar PV costs is [5], as it was available in June 2017. The cost numbers are shown in Table 5. Only numbers for large scale utility systems were available, so they were used to model all solar PV investments. No value was given for variable O&M, so it was assumed to be zero. The costs refer to installed capacity in MWp, which means installed peak capacity (or “DC capacity”). The CF numbers reported in 5.4 for solar PV also refer to installed MWp values, so the CFs and costs are aligned.

It can be seen in Table 5 that a very significant investment cost reduction is foreseen for solar PV going from today to 2050 (64 %). As a percentage, this is larger than the investment cost reduction expected for any wind generation type (as shown in Table 4).

Table 5: Solar PV costs.

	Today (2015)	2030	2050
Investment (M€/MWp), total system	1.07	0.50	0.39
Fixed O&M (€/MW/y)	12864	8748	7440
Variable O&M (€/MWh)	N/A	N/A	N/A
Technical lifetime (years)	30	40	40

The costs are given in €2015.

4.3 Conventional technology costs

Investments in gas turbines, combined cycle gas turbines, wood pellets steam turbines, and on-land AC transmission are also included in the Balmorel investment optimization model. For GB, possibility to invest in Nuclear energy was also included. These technologies were included to create a competition between traditional technologies and VRE generation and increased transmission capacity.

The costs and technical characteristics of the gas turbines, combined cycle gas turbine, and wood pellets steam turbine technologies were obtained from [5]. AC transmission line costs were taken from [2]. Finally, the source for the nuclear technology costs was [9].

5. VRE generation simulations and investable capacities

This chapter starts by describing the CorRES tool that was used for simulating the VRE generation time series for Balmorel modelling. The assumptions about VRE technology development towards 2050 used in the CorRES simulations are then presented. Finally, assumptions about investable VRE capacities in the different scenarios are described, and the resulting CFs for different VRE generation types for the different countries are presented.

5.1 The CorRES tool

The CorRES (Correlations in Renewable Energy Sources) tool is a VRE generation simulation software developed at DTU Wind Energy [10]. It adds solar PV simulation capabilities to the previously developed CorWind tool, which was created for analysing variability in wind generation. CorRES combines meteorological reanalysis techniques and stochastic simulation to enable generation of wind and solar PV time series for current and future scenarios. The following subsections briefly describe the reanalysis data and the stochastic simulation used in CorRES.

5.1.1 Meteorological reanalysis data

CorRES is based on reanalysis data obtained from the Weather Research and Forecasting (WRF) model [11]. As WRF is a mesoscale model, downscaling [12], [13] has been used to generate time series of meteorological variables, most importantly wind speed and irradiance.

From WRF modelling, hourly meteorological time series are obtained on a 10 km x 10 km grid. Covering the area of interest, such grid of data enables modelling of VRE generation in future scenarios with a changing geographical distribution of installations. For the analyses shown in this report, 34 years of WRF data were available for generating the VRE time series.

5.1.2 Stochastic fluctuation modelling

Variations are smoothened in simulated winds from mesoscale models, such as WRF, because of spatial and temporal averaging effects. This generally causes an underestimation of short-term variability in wind speeds [14]. To generate more representative simulations, fluctuations are added to the reanalysis wind speeds in CorRES. Utilising a stochastic simulation model based on [15], the combination of reanalysis data and fluctuations ensures realistic wind speed simulations.

The detailed modelling of short-term variability is especially important in the analysis of large OWPPs [16], compared to usually more dispersed onshore wind installations. Because of this, and due to computational limitations (onshore wind simulations can include very large number of simulation points), fluctuations were added only to offshore wind simulations.

5.1.3 To generation time series

The conversion from meteorological data to VRE generation time series in large-scale simulations has been shown in [17], [18]. Using reanalysis wind speeds directly can cause erroneous CFs in the simulations [17], [19]. To remedy this, historical CF data has been used to calibrate wind speeds in CorRES, using an approach similar to [19]; WRF wind speeds were scaled to match historical CFs estimated from publicly available sources. The conversion from simulated wind speeds to power output is carried out with power curves aligned with the data in [5], as described in the next section. This ensures that simulated CFs are coordinated with the assumed wind power costs. Solar PV CFs and costs are also aligned to [5].

5.2 Assumptions about future VRE installations

This section describes the assumptions made about VRE installations for the scenarios towards 2050. Both foreseen technological developments and assumptions about the amounts of investable VRE capacities are presented.

5.2.1 Technological development of wind generation

For the CorRES modelling, technical wind power plant parameters are required to estimate the CFs of the investable wind power capacities. The hub heights of future wind power installations for 2030 and 2050 are taken from [5] (as it was available in July 2017), with onshore wind going towards 110 m and offshore wind towards 140 m by 2050. In addition, as in [5], specific power is assumed to decrease, which further increases the CFs of future wind power installations. The same technical parameters are assumed for all regions; however, different wind conditions and different available investment locations cause the wind CFs to be very different for different regions, as show in section 5.4. For solar PV generation, CFs are foreseen to change less than for wind in the future.

5.2.2 Available investable offshore wind power capacity

The amount of investable offshore wind power capacity is based on a database at DTU Wind Energy on future OWPP plans. The database is based on data from [21]. Although first analysed project by project, the investable capacities are grouped by technology and geographical area to provide input for the Balmorel investment optimization. The different offshore technology types are described in section 4.2.2. An overview of the investable offshore wind GW in the project-based scenario is shown in Table 6 per country; more details are given in Appendix B. In total, the scenarios can reach to more than 150 GW of offshore wind in the analysed countries by 2050.

In the offshore grid scenario, many of the OWPPs that were considered HVDC connectable in the project-based scenario, are considered to be hub-connectable. This is shown in Figure 13, where the investable hub-connected offshore wind is shown for each hub considered in the offshore grid scenario.

Table 6: Investable offshore wind capacities in the project-based scenario.

	Installed by 2020 (GW)	Investable in Balmorel (GW)	Possible total by 2050 (GW)
BE	1.6	4.5	6.0
DK	1.7	7.5	9.2
GB	10.5	43.3	53.7
NL	1.1	24.9	26.0
NO	0.0	18.3	18.3
DE	7.4	36.0	43.4
Total	22.2	134.4	156.6

The GW installed by 2020 are calculated by summing up the commissioned and in-construction OWPPs in the DTU Wind Energy's OWPP database (based on [21]). The investable offshore GW are taken from the same source by looking at future planned OWPPs. The possible total by 2050 is the sum of these two.

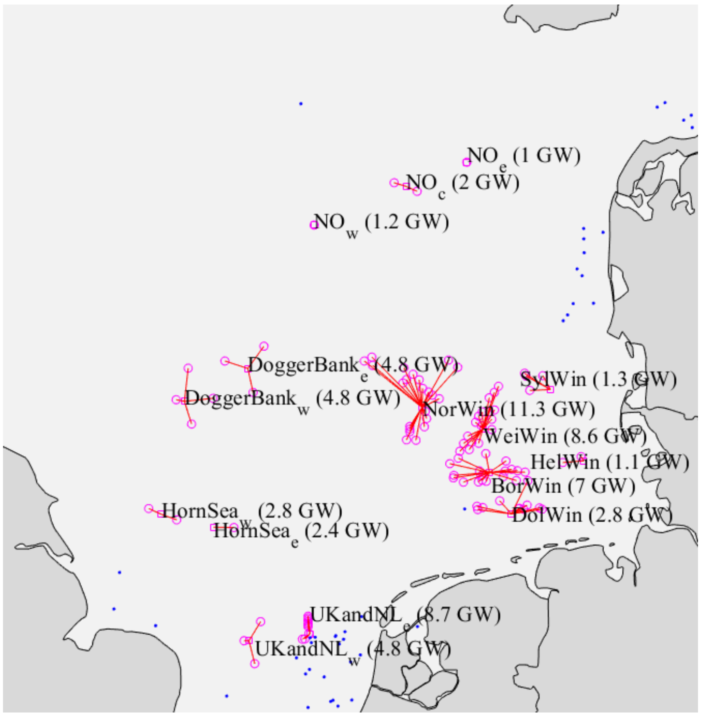

Figure 13: Investable hub-connected offshore wind capacities in the offshore grid scenario. The OWPPs connected to hub $UKandNL_w$ are UK ones, and the ones connected to $UKandNL_e$ are Dutch. All DoggerBank and HornSea OWPPs are UK ones, and all hubs ending in "Win" consist of German OWPPs.

5.2.3 Available investable onshore VRE capacities

An overview of the investable onshore wind capacities is shown in Table 7. The table also shows the capacities assumed to be installed by 2020 (the starting point of the investment optimization). The installations by 2020 are taken as the 2020 scenario from [2]; however, the numbers were compared to the expected onshore wind development towards 2020 in [24]; for NL and GB, the installations expected by 2020 in [2] significantly exceed the development seen in [24]. Thus, for NL and GB the expected onshore wind installations by 2020 are calculated utilising the WindEurope numbers [22], [23], [24].

As was described in section 2.1.3, both the project-based and the offshore grid scenario were modelled with two different assumptions about available investable onshore wind; the two cases are called high onshore wind and low onshore wind. For the high onshore wind case, the potentials by 2050 are taken from [2], and the investable capacities for Balmorel are calculated as shown in Table 7; more detailed information is given in Appendix A. In the low onshore wind case, the 2030 HIGH scenario numbers from [25] are utilized; it was considered that for NSON-DK scenarios looking towards 2050, those numbers approximate a low onshore wind scenario by 2050.

As can be seen in Table 7, DE is foreseen to have significant onshore wind capacity to be invested in. GB has the second most investable onshore wind; however, in the low onshore wind case the possible total is quite limited. In addition to the investable capacities, there are significant differences between the countries considering what CFs the investments can be expected to have. These differences are presented in Section 5.4.2.

For solar PV, the capacity potentials by 2050 are taken from [26]. To get investable GW for the scenarios, the capacities assumed by 2020 are subtracted from the overall potentials: resulting numbers are shown in Appendix C. Expected CFs for solar PV are presented in section 5.4.3.

Table 7: Investable onshore wind capacities in the two onshore wind cases.

		High onshore wind		Low onshore wind	
	Installed by 2020 (GW)	**Investable in Balmorel (GW)**	**Possible total by 2050 (GW)**	**Investable in Balmorel (GW)**	**Possible total by 2050 (GW)**
BE	2.3	6.7	9.0	2.1	4.4
DK	4.1	3.9	8.0	2.4	6.5
GB	11.9	26.4	38.4	8.1	20.0
NL	4.9	5.4	10.3	5.4	10.3
NO	3.5	10.5	14.0	7.5	11
DE	49.5	49.2	98.7	21.5	71.0
Sum	76.2	102.1	178.3	47.0	123.2

The subtraction of the expected installations by 2020 from the 2050 potentials gives the investable capacities to be used in the investment optimization for the two onshore wind cases.

5.3 Spatiotemporal dependencies in the simulations

In addition to using the CorRES tool to estimate CFs, the simulated time series incorporate the important spatiotemporal dependencies in weather dependent VRE generation. Even though only 4 weeks are used in the Balmorel investment optimization (as explained in section 3.2.2), two important facts remain: 1) each week is a full week on hourly level, which means that within each week the temporal dependencies in VRE generation are considered; and 2) The same 4 weeks are selected for each region, which means that the Balmorel modelling incorporates the important spatial dependencies in VRE generation. The capabilities of CorRES to model the spatiotemporal dependencies in large-scale wind and solar PV generation are shown in [17], [18], [20]. An example spatial dependency of the simulations is shown in Figure 14.

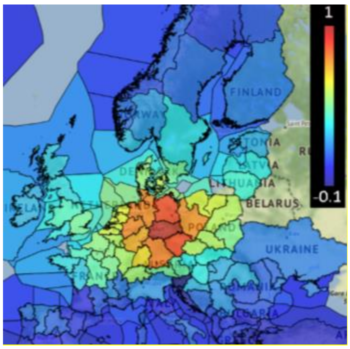

Figure 14: Spatial correlations in wind generation calculated looking from an example German onshore region (using 34 years of simulated hourly data).

5.4 Capacity factors of the investable VRE capacity

This section describes the CFs of the investable VRE generation capacities in the 2030 and 2050 scenario years. The CFs are estimated utilising the CorRES software, as explained in 5.1, using the technological development assumptions presented in Section 5.2.1. Especially for onshore wind, with limitations on how many GW can be invested in different regions, the available wind conditions significantly affect the CFs of possible new investments.

5.4.1 Offshore wind capacity factors

Average offshore wind CFs of the capacities investable in Balmorel are shown in Table 8. These values are averages of the offshore grid scenario; values are similar in the project-based scenario, but of course hub-connected wind is not available. More detailed numbers are given in Appendix B. It can be seen that CFs increase when going from nearshore towards hub-connected offshore wind, which is expected as further offshore is expected to have higher wind speeds. Investments in 2050 have higher expected CFs, as technology is expected to develop in time.

Table 8: Average offshore wind capacity factors in the offshore grid scenario.

	If invested in 2030	**If invested in 2050**
Nearshore	0.46	0.50
Offshore (HVAC)	0.51	0.54
Offshore (HVDC)	0.53	0.55
Hub-connected	0.54	0.57

5.4.2 Onshore wind capacity factors

Onshore wind total GW potentials are split to three resource grades following the approach in [26]: the first grade includes the best 10 %, the second best the next 30 %, and the third grade fills the rest of the total GW potential. Expected CFs of the grades decrease from the best to the lowest grade. It is assumed that current installations are in the best locations, so for most regions the best grades are already utilised completely; for example in DE, already half of total onshore wind resource is invested in, as shown in Table 7. As decommissioning of old wind installations is not modelled, the best resource grades are not available for investments in DE.

Figure 15 shows as an example for three countries: the resulting onshore wind CFs for the investable onshore wind power in 2030 in the high onshore wind case. They result from CorRES simulation runs, when considering the technological development described in Section 5.2.1 and the split to three resource grades explained above; more detailed numbers are given in Appendix A. Two levels are shown for GB, as no investable onshore wind is left in the best grade. DK shows also two levels, but they refer to the two regions (DKe and DKw); it is assumed that by 2020 all best and second best resource grades are already used in DK. DE shows many different CF levels, because there are 4 regions with different resource grades; however, as described in the previous paragraph, the best resource grades are already assumed to be fully utilised, and thus not available for new investments (regional numbers are given in Appendix A).

Figure 16 shows average wind speeds in the North Sea region. When comparing to Figure 15, the following observations can be made: 1) Although in DK only the third onshore wind resource grade is investable, the CFs are still high due to the high wind speeds all around DK. 2) GB shows high wind speeds all over the region; thus, even the third onshore wind resource grade can be built with quite high CF. 3) DE has a lot of investable onshore wind; however, the CFs drops significantly when more wind is installed. This is in line with the Figure 16 wind speed map: the areas in northern Germany offer good CFs, but when moving to south the mean wind speeds drops significantly.

For the low onshore wind case, the reduction of investable GW is done on the third resource grade. I.e., the best two grades have the same amount of investable GW as in the high onshore wind case, but the investable capacities of the third resource grade are reduced.

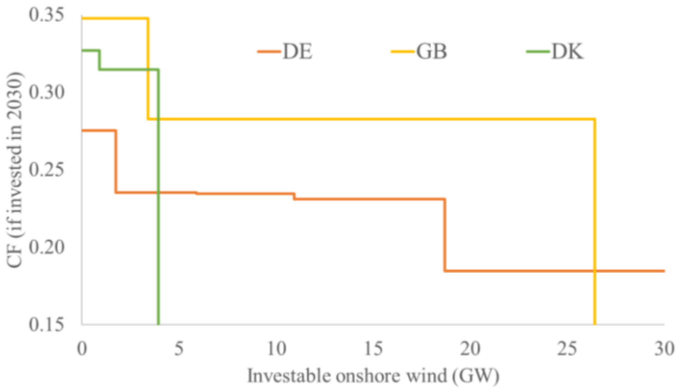

Figure 15: Estimated CFs of investable onshore wind power in three example countries for the high onshore wind case, if invested in 2030 (with technology development explained in 5.2.1). The investable onshore wind GW for Germany is higher (49.2 GW) than what is visible in the figure.

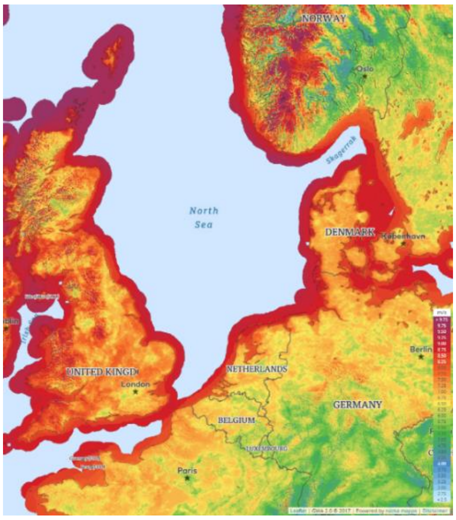

Figure 16: Global Wind Atlas mean wind speeds at 100 m for the onshore areas around the North Sea region (also for some offshore areas) [27].

5.4.3 Solar PV capacity factors

For solar PV, a split to three resources grades (10%, 30 % and 60 % of total GW potential) similar to onshore wind was carried out, following the approach in [26]. As can be seen in Appendix C, solar PV CFs are the highest in the south, and lowest in the north; E.g., the northern most Norwegian region has a CF of only around 7-9 %, whereas in the southernmost German region the expected CF is around 11-13 %. The different solar PV resources grades of a region have relatively similar CFs: e.g., in BE the best grade has a CF of 11.8 %, while the lowest grade CF is 10.7 %, if invested in 2030. Thus, solar PV allows for installations with a relatively uniform CF around a region; a significant difference compared to onshore wind, as was described in the previous subsection.

The solar PV CFs change less than onshore wind when going from 2030 to 2050; e.g., in NL the best grade's CF in 2030 is 11.8 %, and in 2050 it is 12.5 % (more information in Appendix C). However, the important difference in solar PV for the investment optimization going from 2030 to 2050 is the significant drop in costs, as was shown in section 4.2.3.

6. Resulting scenarios

This chapter presents the NSON-DK scenarios resulting from the Balmorel investment optimization. As was outlined in Chapter 2, a project-based and an offshore grid scenario is presented. The main NSON-DK scenarios are presented in the first section, and the following sections show how different modelling assumptions and cost parameters affect the resulting scenarios: the effects of how much onshore wind is investable, intertemporal optimisation, and transmission line costs are studied.

6.1 NSON-DK scenarios

This section presents the project-based and the offshore grid NSON-DK scenarios, which are the main scenarios to be used in the NSON-DK project. The scenarios use the limited onshore wind case (as described in section 5.2.3). They are optimised using the intertemporal optimisation, as described in section 3.1.2, and the transmission line costs described in section 4.1.2. In addition to transmission development and generation capacity investments, expected annual energies per generation type are given for the scenario years 2030 and 2050.

6.1.1 Project-based scenario

The North Sea area transmission development towards 2050 in the project-based scenario is shown in Figure 17 (investments are made on top of the assumed exogenous transmission development shown in Figure 6). It can be seen that the optimization sees value in increasing connections from NO to the other countries to combine the flexible Norwegian hydro generation to the increasing VRE generation shares in all countries. This is in line with the results shown, e.g., in [1]. In addition, significant increase in transmission capacity from DE to GB is seen via BE. It can be seen that significant transmission development is seen already by 2030; this is discussed more in section 6.3.

The VRE and fossil condensing generation capacities in the project-based scenario are shown in Table 9. Both solar PV and wind see high installed capacities already by 2030 (the rapid development is discussed in section 6.3). Due to the expected decommissioning of fossil condensing generation, as presented in section 2.2.5, the total fossil condensing GW gets very low in 2050. The 4.5 GW of fossil generation in GB are new gas investments; without investments, the decommissioning would lead to 0 GW of fossil condensing by 2050. The scenario includes also significant hydro, almost all of it in NO. And as decommissioning of CHP is not modelled, as described in section 2.2.5, there is gas CHP generation still in 2050. Energy generation from the different generation sources is discussed in section 6.1.3.

The feasibility of the very low fossil condensing capacity in 2050, as seen in Table 9, will be investigated in NSON-DK WP3 and WP4, where balancing and adequacy modelling is carried out.

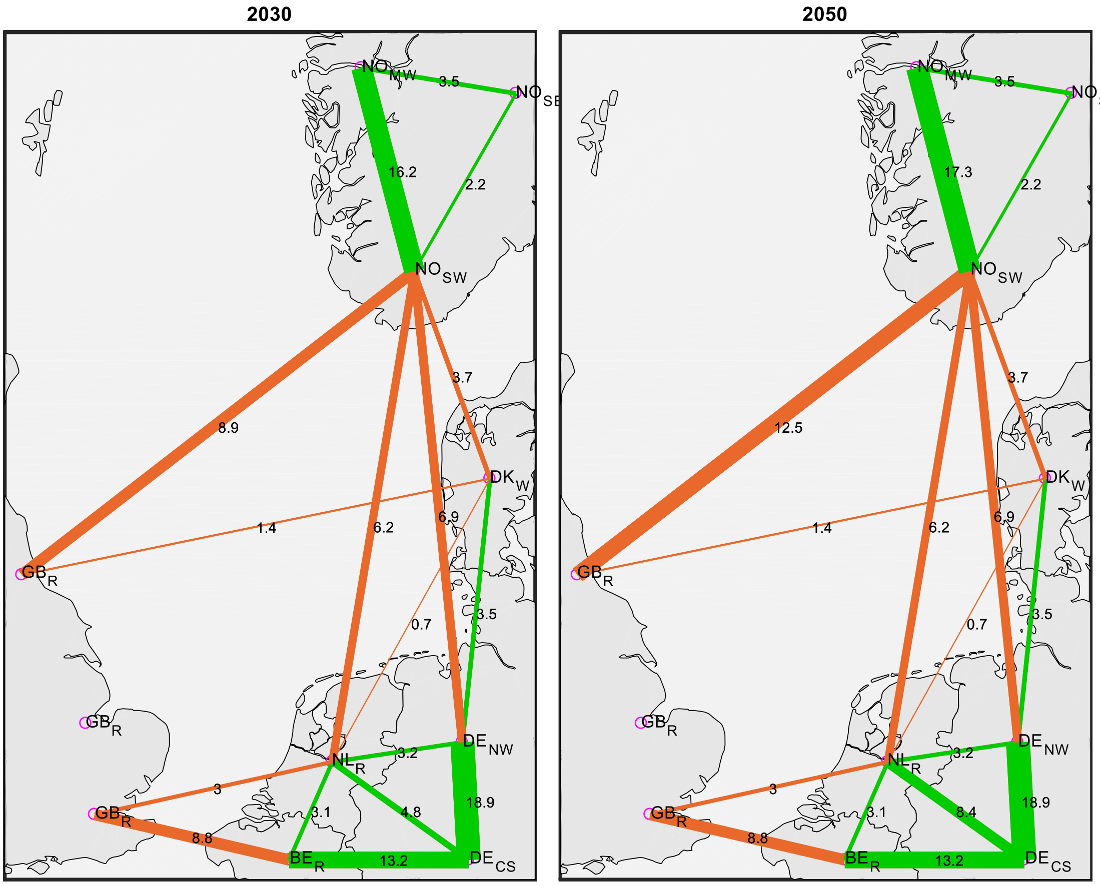

Figure 17: **Project-based scenario**: transmission lines in 2030 and 2050 (GW) between regions visible in the map. On-land lines in green and C2C offshore lines in orange.

Table 9: **Project-based scenario**: installed VRE and fossil condensing capacities (GW).

	Solar PV			Offshore wind			Onshore wind			Fossil Condensing		
	2020	**2030**	**2050**	**2020**	**2030**	**2050**	**2020**	**2030**	**2050**	**2020**	**2030**	**2050**
BE	3.4	12.6	12.6	1.6	6.0	6.0	2.3	4.4	4.4	10.8	5.1	
DE	52.0	74.5	74.5	7.4	16.8	16.8	49.5	63.5	65.0	21.9	10.4	
DK	0.9	9.0	9.0	1.7	6.2	8.1	4.1	6.5	6.5	0.7	0.3	
GB	11.5	50.5	58.3	10.5	32.2	37.9	11.9	20.0	20.0	43.9	20.8	4.5
NL	1.9	23.7	24.6	1.1	13.4	16.3	4.9	4.9	7.4	15.9	7.5	
NO			0.2	0.0	7.0	10.7	3.5	9.9	9.9	0.3	0.1	
Sum	69.8	170.3	179.3	22.2	81.7	95.8	76.2	109.2	113.3	93.6	44.3	4.5

6.1.2 Offshore grid scenario

The North Sea area transmission development towards 2050 in the offshore grid scenario can be seen in Figure 18 (investments are made on top of the assumed exogenous development shown in Figure 6). It can be seen that hubs are integrated as part of the transmission infrastructure for transmission corridors connecting NO to the other countries. In addition, GB is connected to continental Europe both with C2C lines and via hubs. Thus, the Balmorel optimisation sees value in utilising a mixture of C2C lines and an integrated offshore grid for increasing transmission capacity.

The most significant utilisations of an integrated structure using hubs can be seen in two places. Firstly, in connecting NO to GB, NL and DE via the Norwegian hubs. Secondly, the large concentration of German hub-connected offshore wind generation of more than 10 GW is connected to a multitude of countries: DE, NL, GB and NO.

Table 10 shows that only German and Norwegian hubs are built in the scenario year 2030. In 2050, a British hub is built, but connected only radially to GB and not utilised as part of the offshore grid. Compared to the project-based scenario presented in the previous subsection, the offshore grid scenario shows around 4 GW more offshore wind investments by 2050; leading in total to around 100 GW of offshore wind in the analysed region. The strong development already by 2030 is discussed in section 6.3.

It can be seen that Dutch offshore wind looks lower compared to the project-based scenario (Table 10 vs. Table 9); however, when looking at the map (Figure 18), it can be seen that the German hubs are strongly connected to NL. Thus, although listed under DE in Table 10, the German hub-connected offshore wind is also providing energy to NL.

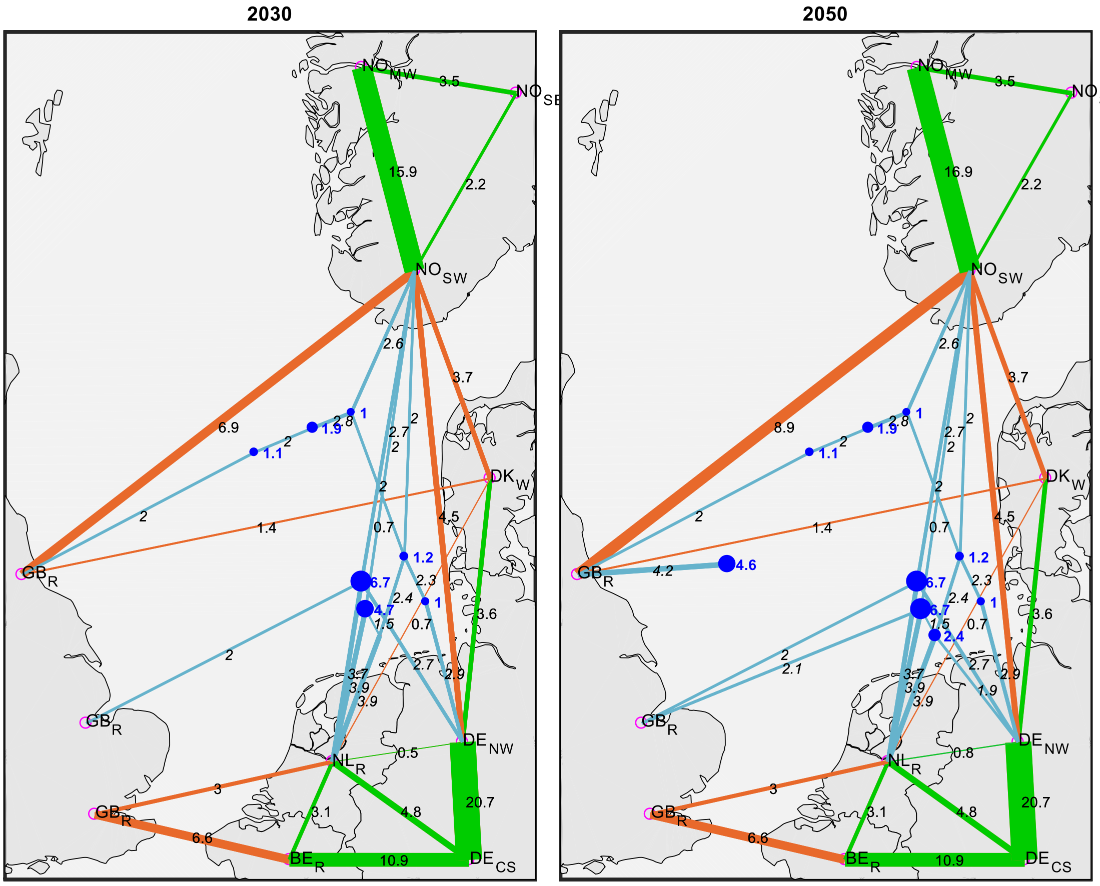

Figure 18: **Offshore grid scenario**: transmission lines and hubs in 2030 and 2050 (GW) between regions visible in the map. On-land lines in green, C2C offshore lines in orange, lines related to the meshed grid in light blue and hubs in dark blue.

Table 10: **Offshore grid scenario**: installed VRE and fossil condensing capacities (GW).

	Solar PV			Offshore wind (in brackets: share of hub-connected)			Onshore wind			Fossil Condensing		
	2020	2030	2050	2020	2030	2050	2020	2030	2050	2020	2030	2050
BE	3.4	14.4	14.4	1.6	6.0	6.0	2.3	4.4	4.4	10.8	5.1	
DE	52.0	79.5	79.5	7.4	28.2 (51%)	32.8 (57%)	49.5	62.1	64.6	21.9	10.4	
DK	0.9	9.0	9.0	1.7	6.2	7.7	4.1	6.5	6.5	0.7	0.3	
GB	11.5	52.4	60.4	10.5	31.1	37.6 (13%)	11.9	20.0	20.0	43.9	20.8	4.2
NL	1.9	16.5	16.5	1.1	4.7	6.9	4.9	4.9	4.9	15.9	7.5	
NO			0.2	0.0	7.2 (58%)	8.6 (49%)	3.5	8.0	8.0	0.3	0.1	
Sum	69.8	171.7	180.0	22.2	83.5 (22%)	99.7 (28%)	76.2	105.9	108.4	93.6	44.3	4.2

6.1.3 Annual energy generation

This section shows how the project-based and the offshore grid scenario look in terms of expected annual energy generation. As seen in Table 11, already by 2030 both NO and DK are expected to become significant electricity exporters. Assumed decommissioning of generation is a major driver for this: as can be seen in Figure 7 and Figure 8, NL, BE, GB and DE experience significant decommissioning of thermal and nuclear generation. In addition, the expected increase in CO_2 price (Figure 4) penalises the use of fossil fuels. While those countries see significantly increased VRE capacities, as shown in the previous subsections, the resulting lack of generation is also met by increasing VRE generation in DK and NO. As NO sees no and DK only limited decommissioning (as explained in section 2.2.5), some of the additional VRE generation in these countries is available for exporting. GB, with good wind resources, approximately meets its demand in annual TWh terms, NL changes from net importer in 2030 to exporter in 2050, and DE and BE are net importers in both scenario years. More numbers are given in Appendices D and E.

Comparing Table 11 and Table 12, DE and NL seem to be significantly different in the project-based scenario compared to the offshore grid one. However, as discussed in the previous subsection, this can be explained by offshore wind moving from NL to the German hubs connected to NL. Both the project-based and the offshore grid scenario see some net export to the whole analysed region.

Table 13 shows an overview of the expected shares of different generation types in the main NSON-DK scenarios. It can be seen that already by 2030 offshore wind is expected to have the largest TWh share in the analysed region. VRE generation plus hydro generates around 90 % of the annual energy by 2050 in both scenarios. Some CHP is generated by gas, as CHP is used in heating following the assumptions presented in section 2.2.5. More detailed numbers are given in Appendices D and E.

More detailed analysis of the annual energy generation will be carried out in NSON-DK WP3, when hourly runs covering the whole year (and not only the modelled 4 weeks) are carried out.

Table 11: **Project-based scenario**: Expected annual generations, consumptions, losses and net exports.

	Energy balance in 2030 (TWh)				Energy balance in 2050 (TWh)			
Country	Generation	Demand	Losses	Net export	Generation	Demand	Losses	Net export
BE	58.1	84.6	0.8	-27.3	49.9	81.8	0.8	-32.8
DE	448.1	564.6	5.6	-122.1	410.9	546.8	5.5	-141.3
DK	66.9	40.6	0.4	25.9	68.0	40.3	0.4	27.3
GB	331.1	341.5	3.4	-13.8	304.2	330.4	3.3	-29.4
NL	100.6	111.7	1.1	-12.2	113.3	108.0	1.1	4.2
NO	200.1	122.5	1.2	76.4	223.2	111.0	1.1	111.1
Sum	1205.0	1265.4	12.6	-73.1	1169.5	1218.3	12.2	-61.0

Table 12: **Offshore grid scenario**: Expected annual generations, consumptions, losses and net exports.

	Energy balance in 2030 (TWh)				Energy balance in 2050 (TWh)			
Country	Generation	Demand	Losses	Net export	Generation	Demand	Losses	Net export
BE	59.7	84.6	0.8	-25.7	51.4	81.8	0.8	-31.3
DE	504.5	564.6	5.6	-65.8	488.6	546.8	5.5	-63.6
DK	66.9	40.6	0.4	25.9	66.0	40.3	0.4	25.3
GB	326.2	341.5	3.4	-18.7	301.9	330.4	3.3	-31.8
NL	55.5	111.7	1.1	-57.2	59.0	108.0	1.1	-50.2
NO	197.3	122.5	1.2	73.6	210.3	111.0	1.1	98.2
Sum	1210.1	1265.4	12.6	-67.9	1177.2	1218.3	12.2	-53.3

Table 13: Expected shares of the different generation types in the main NSON-DK scenarios.

		WIND-ONS	WIND-OFF	SOLAR	HYDRO	NUCLEAR	GAS - CHP	FOSSIL - CND	OTHER THERMAL
2030	Project-based	22%	29%	14%	14%	6%	9%	1%	4%
	Offshore Grid	21%	30%	14%	14%	6%	9%	1%	4%
2050	Project-based	24%	35%	15%	15%	2%	7%	0%	2%
	Offshore Grid	22%	37%	15%	15%	2%	7%	0%	2%

The shares (compared to aggregate generation) are calculated based on numbers shown in Appendices D and E.

6.2 Impact of onshore wind potentials

This section compares the main NSON-DK scenarios, as presented in the previous section, to optimisation results assuming the high onshore wind case (as shown in section 5.2.3). Both the project-based and the offshore grid scenario are compared in relation to transmission development and generation capacity investments.

6.2.1 Project-based scenario: high onshore wind

The North Sea area transmission development towards 2050 in the project-based high onshore wind scenario is shown in Figure 19. Related VRE and fossil condensing GW are shown in Table 14. Compared to the main project-based scenario, as presented in section 6.1.1, NO-GB connection is even stronger, as is the connection between DE and GB via BE.

As expected, overall onshore wind GW is increased, with especially GB seeing more onshore wind in the high onshore wind case compared to the main project-based scenario (section 6.1.1). Overall Solar PV installations are similar compared to the main scenario, but increased onshore wind GW decreases the offshore wind development; there is expected to be around 8 GW less offshore wind by 2050 in the project-based high onshore wind scenario compared to the main project-based scenario.

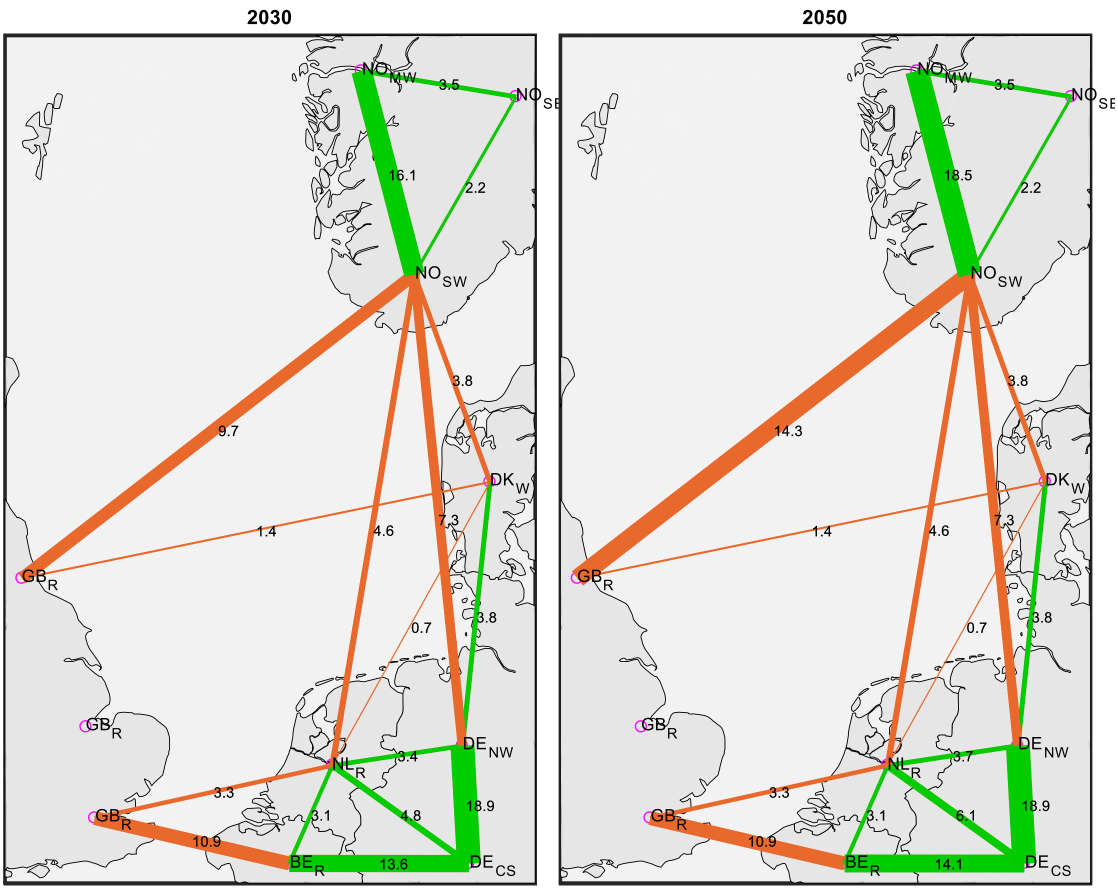

Figure 19: **Project-based *high onshore wind* scenario**: transmission lines in 2030 and 2050 (GW) between regions visible in the map. On-land lines in green and C2C offshore lines in orange.

Table 14: **Project-based *high onshore* wind scenario**: installed VRE and fossil condensing capacities (GW).

	Solar PV			Offshore wind			Onshore wind			Fossil Condensing		
	2020	2030	2050	2020	2030	2050	2020	2030	2050	2020	2030	2050
BE	3.4	8.6	8.6	1.6	6.0	6.0	2.3	9.0	9.0	10.8	5.1	
DE	52.0	71.3	71.3	7.4	16.8	16.8	49.5	62.1	64.0	21.9	10.4	
DK	0.9	9.0	9.0	1.7	6.2	7.5	4.1	8.0	8.0	0.7	0.3	
GB	11.5	49.4	61.1	10.5	29.9	31.7	11.9	38.4	38.4	43.9	20.8	3.2
NL	1.9	28.8	28.8	1.1	10.6	14.4	4.9	4.9	4.9	15.9	7.5	
NO		0.2	0.2	0.0	3.9	11.4	3.5	8.4	8.4	0.3	0.1	
Sum	69.8	167.3	179.0	22.2	73.4	87.8	76.2	130.8	132.7	93.6	44.3	3.2

6.2.2 Offshore grid scenario: high onshore wind

The North Sea area transmission development towards 2050 in the offshore grid high onshore wind scenario can be seen in Figure 20. Related VRE and fossil condensing GW are shown in Table 15. Compared to the main offshore grid scenario, as presented in section 6.1.2, the high onshore wind scenario shows less offshore wind. In addition to the total offshore wind capacity being around 12 GW lower by 2050, a smaller share of it is hub connected compared to the main offshore grid scenario. Especially German offshore wind is capacity is much lower, with less hub-connected GW. The single British hub shows an interesting effect of using the intertemporal optimisation: a connection (with no generation) is built already in 2030; waiting for hub-connected generation investment in 2050.

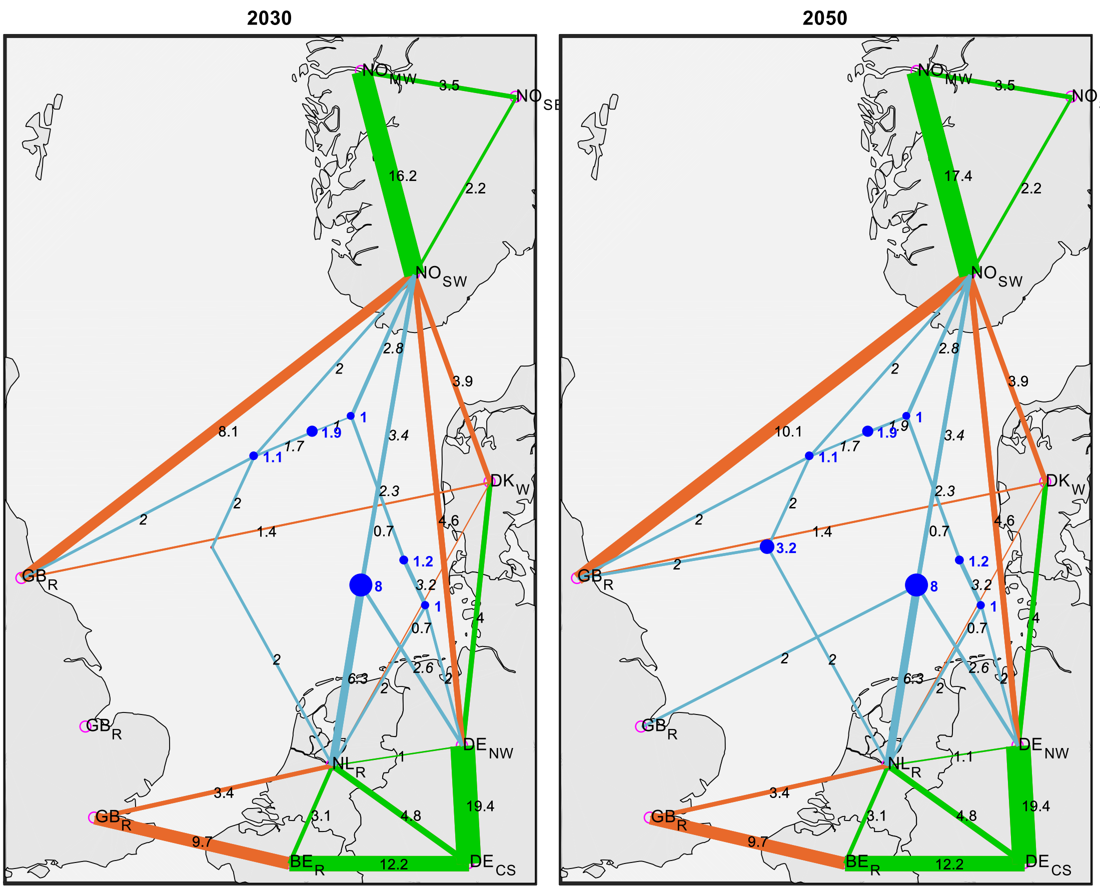

Figure 20: **Offshore grid *high onshore* wind scenario**: transmission lines and hubs in 2030 and 2050 (GW) between regions visible in the map. On-land lines in green, C2C offshore lines in orange, lines related to the meshed grid in light blue and hubs in dark blue.

Table 15: **Offshore grid *high onshore* wind scenario**: installed VRE and fossil condensing capacities (GW).

	Solar PV			Offshore wind (in brackets: share of hub-connected)			Onshore wind			Fossil Condensing		
	2020	**2030**	**2050**	**2020**	**2030**	**2050**	**2020**	**2030**	**2050**	**2020**	**2030**	**2050**
BE	3.4	8.6	8.6	1.6	6.0	6.0	2.3	9.0	9.0	10.8	5.1	
DE	52.0	74.6	74.6	7.4	24.6 (44%)	24.7 (44%)	49.5	61.2	64.2	21.9	10.4	
DK	0.9	9.0	9.0	1.7	6.2	7.6	4.1	8.0	8.0	0.7	0.3	
GB	11.5	53.3	62.9	10.5	27.0	33.4 (10%)	11.9	38.4	38.4	43.9	20.8	3.2
NL	1.9	25.9	25.9	1.1	2.2	5.0	4.9	4.9	4.9	15.9	7.5	
NO		0.1	0.2	0.0	7.2 (58%)	10.4 (40%)	3.5	8.0	8.0	0.3	0.1	
Sum	69.8	171.4	181.2	22.2	73.1 (20%)	87.2 (21%)	76.2	129.5	132.5	93.6	44.3	3.2

6.3 Impact of intertemporal optimisation

This section compares the main NSON-DK scenarios, as presented in section 6.1, to optimisation results without intertemporal optimisation (i.e., myopic optimisation). Both the project-based and the offshore grid scenario are compared in relation to transmission development and generation capacity investments.

6.3.1 Project-based scenario: myopic optimisation

The North Sea area transmission development towards 2050 in the project-based myopic optimisation scenario can be seen in Figure 21. Related VRE and fossil condensing GW are shown in Table 16. Comparing to the main project-based scenario (section 6.1.1), the VRE capacities in 2030 are significantly lower in the myopic scenario; especially offshore wind, which is around 13 GW lower in 2030. In addition to VRE capacities, the transmission development by 2030 is less in the myopic scenario compared to the main scenario. This shows the importance of looking ahead when making investment decisions on a specific year; if there is a strong commitment to rising CO_2 price toward 2050, as was assumed in section 2.2.2, the relative value of VRE generation installed in 2030 is increased compared to competing fossil based generation.

Looking at the scenario by 2050 in the myopic optimisation (Figure 21 and Table 16), and comparing the main scenario results in section 6.1.1, it can be seen that the overall level of VRE capacity by 2050 is quite similar; however, offshore wind is expected to be a few GW less in the myopic scenario. Although the transmission set-up is a bit different in the myopic scenario compared to the main scenario in 2050, the overall level of transmission is similar. Therefore it can be concluded that both the myopic and the intertemporal optimisation lead to a relatively similar 2050 scenario year, but via a very different year 2030.

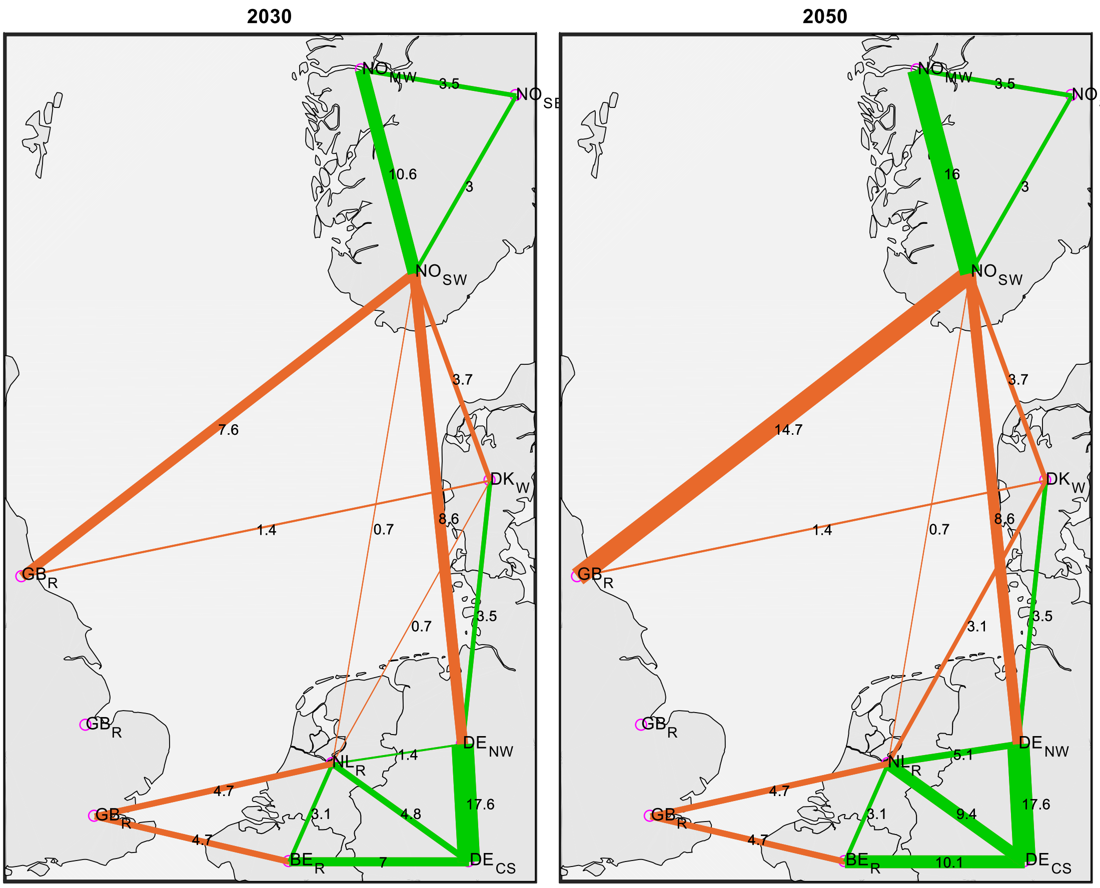

Figure 21: **Project-based *myopic optimisation* scenario**: transmission lines in 2030 and 2050 (GW) between regions visible in the map. On-land lines in green and C2C offshore lines in orange.

Table 16: **Project-based *myopic optimisation* scenario**: installed VRE and fossil condensing capacities (GW).

	Solar PV			Offshore wind			Onshore wind			Fossil Condensing		
	2020	**2030**	**2050**	**2020**	**2030**	**2050**	**2020**	**2030**	**2050**	**2020**	**2030**	**2050**
BE	3.4	8.6	8.6	1.6	6.0	6.0	2.3	4.4	4.4	10.8	5.1	
DE	52.0	85.4	85.4	7.4	12.9	16.8	49.5	59.0	64.0	21.9	10.4	
DK	0.9	8.3	9.0	1.7	6.2	8.3	4.1	6.5	6.5	0.7	0.3	
GB	11.5	38.6	51.9	10.5	28.2	36.5	11.9	20.0	20.0	43.9	20.8	5.5
NL	1.9	12.7	24.9	1.1	14.0	16.3	4.9	4.9	9.9	15.9	7.5	
NO				0.0	1.5	9.3	3.5	10.5	10.5	0.3	0.1	
Sum	69.8	153.6	179.8	22.2	68.8	93.2	76.2	105.3	115.3	93.6	44.3	5.5

6.3.2 Offshore grid scenario: myopic optimisation

The North Sea area transmission development towards 2050 in the offshore grid myopic optimisation scenario can be seen in Figure 22. Related VRE and fossil condensing GW are shown in Table 17. As was shown for the project-based scenario in the previous subsection, the offshore grid scenario also sees less development in 2030 when myopic optimisation is used. All VRE capacities are lower in 2030, with especially hub-connected offshore wind much lower than in the main scenario. However, by 2050 the myopic offshore grid scenario shows large offshore wind GW with approximately the same share of it hub-connected as in the main offshore grid scenario (see section 6.1.2).

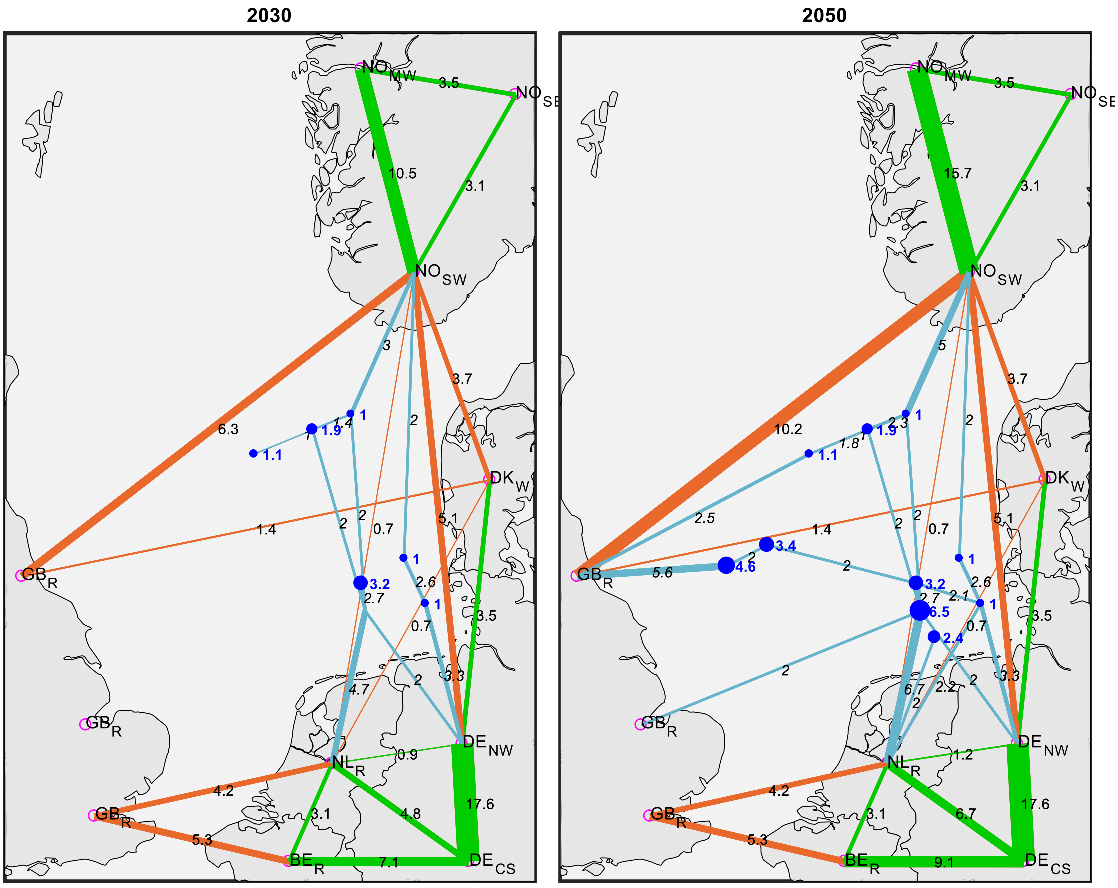

Figure 22: **Offshore grid *myopic optimisation* scenario**: transmission lines and hubs in 2030 and 2050 (GW) between regions visible in the map. On-land lines in green, C2C offshore lines in orange, lines related to the meshed grid in light blue and hubs in dark blue.

Table 17: **Offshore grid *myopic optimisation* scenario**: installed VRE and fossil condensing capacities (GW).

	Solar PV			Offshore wind (in brackets: share of hub-connected)			Onshore wind			Fossil Condensing		
	2020	**2030**	**2050**	**2020**	**2030**	**2050**	**2020**	**2030**	**2050**	**2020**	**2030**	**2050**
BE	3.4	8.6	8.6	1.6	6.0	6.0	2.3	4.4	4.4	10.8	5.1	
DE	52.0	84.5	84.5	7.4	15.5 (36%)	27.1 (55%)	49.5	59.0	64.0	21.9	10.4	
DK	0.9	8.4	9.0	1.7	6.2	7.5	4.1	6.5	6.5	0.7	0.3	
GB	11.5	41.7	59.0	10.5	27.7	39.8 (21%)	11.9	20.0	20.0	43.9	20.8	3.4
NL	1.9	12.7	16.1	1.1	8.4	8.9	4.9	4.9	4.9	15.9	7.5	
NO			0.2	0.0	5.3 (77%)	9.6 (43%)	3.5	8.9	8.9	0.3	0.1	
Sum	69.8	155.9	177.4	22.2	69.1(14%)	98.9 (28%)	76.2	103.7	108.7	93.6	44.3	3.4

6.4 Effect of transmission line costs

This section compares the main NSON-DK scenarios, as presented in section 6.1, to optimisation results with higher transmission line costs; in the sensitivity test the costs shown in 4.1.2 are simply assumed to be double. Both the project-based and the offshore grid scenario are compared in relation to transmission development and generation capacity investments.

6.4.1 Project-based scenario: 2x line costs

The North Sea area transmission development towards 2050 in the project-based 2x line cost scenario can be seen in Figure 23. Related VRE and fossil condensing GW are shown in Table 18. Compared to the main scenario results shown in section 6.1.1, it can be seen that transmission GW are significantly reduced; however, interestingly this does not affect transmission lines connected to DK: they remain similar or even increase (connection to NL in 2050). Looking at the VRE capacities, higher transmission line costs affect offshore wind significantly: it is expected to be around 10 GW lower than in the main project-based scenario by 2050. Solar PV GW are expected to be higher in the 2x line cost scenario, and fossil condensing is expected to be significantly higher than in the main scenario; this highlights the effect of transmission in lowering fossil fuel GW in the scenarios.

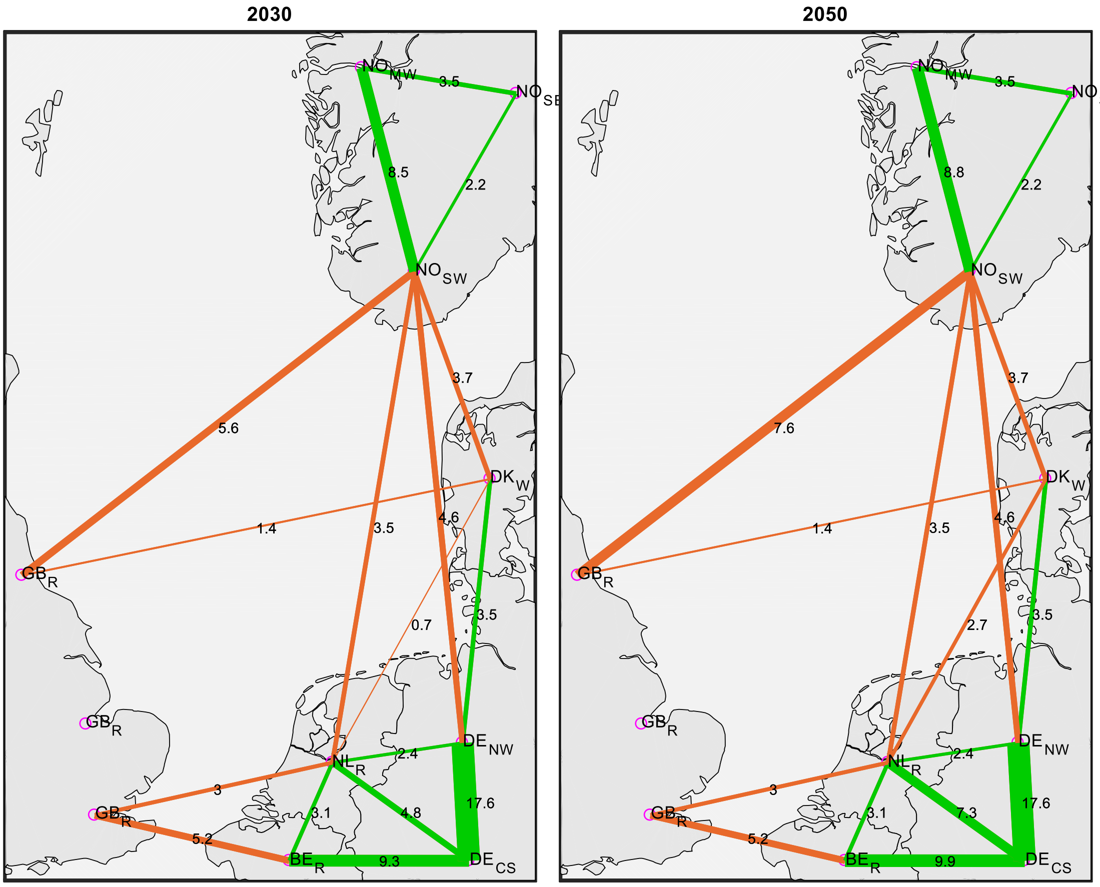

Figure 23: **Project-based *2x line cost* scenario**: transmission lines in 2030 and 2050 (GW) between regions visible in the map. On-land lines in green and C2C offshore lines in orange.

Table 18: **Project-based *2x line cost* scenario**: installed VRE and fossil condensing capacities (GW).

	Solar PV			Offshore wind			Onshore wind			Fossil Condensing		
	2020	2030	2050	2020	2030	2050	2020	2030	2050	2020	2030	2050
BE	3.4	15.4	15.4	1.6	6.0	6.0	2.3	4.4	4.4	10.8	5.1	
DE	52.0	94.8	94.8	7.4	16.6	16.8	49.5	64.0	64.0	21.9	10.4	
DK	0.9	8.0	9.0	1.7	6.2	7.8	4.1	6.5	6.5	0.7	0.3	
GB	11.5	48.3	56.6	10.5	32.2	34.2	11.9	20.0	20.0	43.9	20.8	12.1
NL	1.9	14.2	14.2	1.1	15.6	16.3	4.9	8.8	10.3	15.9	7.5	
NO			0.2	0.0	2.3	4.9	3.5	8.9	9.5	0.3	0.1	
Sum	69.8	180.7	190.2	22.2	79.0	85.9	76.2	112.6	114.7	93.6	44.3	12.1

6.4.2 Offshore grid scenario: 2x line costs

The North Sea area transmission development towards 2050 in the offshore grid 2x line cost scenario can be seen in Figure 24. Related VRE and fossil condensing GW are shown in Table 19. Compared to the main scenario results in section 6.1.2, increasing transmission line costs decrease the overall offshore wind capacity (by about 5 GW); the effect is somewhat smaller than in the project-based scenario shown in the previous subsection. The share of hub-connected offshore wind drops significantly: from around 28 % in the main offshore grid scenario to around 18 % in the 2x line cost scenario. Interestingly, all three Norwegian hubs get built even if the line costs are increased. Also, all connections to DK remain similar compared to the main offshore grid scenario.

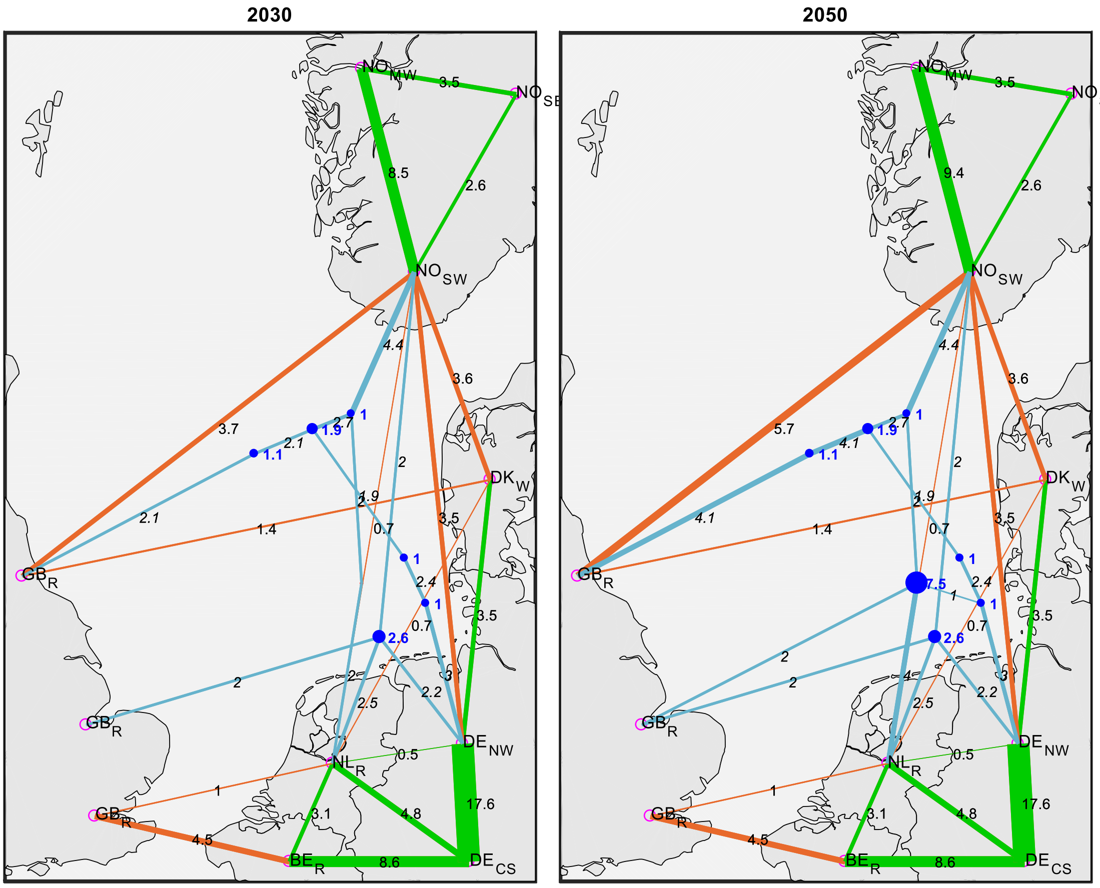

Figure 24: **Offshore grid *2x line cost* scenario**: transmission lines and hubs in 2030 and 2050 (GW) between regions visible in the map. On-land lines in green, C2C offshore lines in orange, lines related to the meshed grid in light blue and hubs in dark blue.

Table 19: **Offshore grid *2x line cost* scenario**: installed VRE and fossil condensing capacities (GW).

	Solar PV			Offshore wind (in brackets: share of hub-connected)			Onshore wind			Fossil Condensing		
	2020	2030	2050	2020	2030	2050	2020	2030	2050	2020	2030	2050
BE	3.4	15.1	15.1	1.6	6.0	6.0	2.3	4.4	4.4	10.8	5.1	
DE	52.0	96.4	96.4	7.4	17.5 (28%)	25.4 (50%)	49.5	64.0	64.0	21.9	10.4	
DK	0.9	8.0	8.6	1.7	6.2	6.9	4.1	6.5	6.5	0.7	0.3	
GB	11.5	47.9	54.9	10.5	30.9	33.2	11.9	20.0	20.0	43.9	20.8	9.8
NL	1.9	12.7	12.7	1.1	15.6	15.6	4.9	4.9	4.9	15.9	7.5	
NO				0.0	5.2 (80%)	7.2 (58%)	3.5	8.0	8.0	0.3	0.1	
Sum	69.8	180.2	187.7	22.2	81.5 (11%)	94.4 (18%)	76.2	107.9	107.9	93.6	44.3	9.8

7. Conclusion

This report has described the energy system scenarios developed in the NSON-DK project. An overall European energy system scenario was used as the basis for the NSON-DK scenarios; however, important updates and modifications were applied to it. Countries in the North Sea region were modelled in detail, and surrounding countries were included as participants in the energy market. The Balmorel energy system model was used to carry out investment optimization for a project-based and an offshore grid scenario.

Updates to the VRE generation costs were described in detail, with especially solar PV and offshore costs expected to decrease significantly. The CorRES tool was used to model the VRE generation. In addition, cost related to the HVDC components were modelled and implemented in Balmorel. Detailed modelling of the HVDC costs is especially important in the offshore grid scenario with a lot of possible lines and hubs; this was achieved utilising MIP modelling in Balmorel.

The capability of Balmorel to model VRE generation and transmission investments simultaneously was used to find optimal shares of different VRE types in the different scenarios, and to optimize the share of C2C lines and utilisation of transmission via hubs in the offshore grid scenario. The resulting scenarios show that going towards an integrated North Sea offshore grid can increase overall offshore wind capacity by several GW by 2050. Germany sees most hub connected offshore wind, while UK is expected to see most offshore wind installations in total. With good wind conditions and strong transmission connections, Denmark is expected to be a significant electricity exporter by 2050.

Three additional analyses were carried out for both the project-based and the offshore grid scenario to test some aspects affecting the resulting scenarios. If more onshore wind can be invested in, the offshore wind share decreases, as can be expected; however, overall solar PV capacity is expected to remain relatively similar. Using myopic optimisation instead of an intertemporal one slows significantly the VRE development by 2030, and more expensive transmission lines decrease the overall amount of transmission; however, connections to DK remain on a similar level even if line costs are increased.

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Appendix A: Onshore wind capacity factors and investable capacities

	CF if invested in 2030 (%)			CF if invested in 2050 (%)			Investable additional capacity (GW)			
Region	1st grade	2nd grade	3rd grade	1st grade	2nd grade	3rd grade	1st grade	2nd grade	3rd grade	Total
NO_MW	47.0	44.1	37.0	48.8	45.8	38.4	0	0.1	0.9	0.9
DK_W	39.9	37.5	31.5	45.2	42.4	35.6	0	0	3.0	3.0
DK_E	37.6	36.0	32.7	43.1	41.2	37.4	0	0	0.9	0.9
GB	42.4	34.8	28.3	47.0	38.6	31.3	0	3.4	23.0	26.4
NO_SW	37.1	34.9	29.2	39.2	36.9	30.9	0	0	0.1	0.1
NO_M	40.4	32.0	28.6	42.7	33.8	30.2	0	0	0.3	0.3
DE_NW	34.9	32.8	27.5	39.4	37.0	31.0	0	0	1.7	1.7
NL	36.5	31.4	25.2	41.0	35.3	28.3	0	0	5.4	5.4
NO_N	38.6	30.6	21.3	40.8	32.4	22.5	0	1.5	3.5	5.0
NO_SE	36.1	28.6	25.6	38.2	30.2	27.1	0.4	1.2	2.5	4.1
BE	30.0	28.7	26.1	34.3	32.8	29.8	0	1.3	5.4	6.7
DE_NE	29.9	28.1	23.5	33.8	31.7	26.6	0	0	4.2	4.2
DE_ME	29.8	28.0	23.5	33.7	31.6	26.5	0	0	5.0	5.0
DE_CS	27.7	23.1	18.5	31.2	26.0	20.8	0	7.8	30.5	38.2
Total							0.4	15.2	86.4	102.1

The numbers for the three different resource grades refer to the high onshore wind case. In the low onshore wind case, the 1st and 2nd grade remain the same, but the investable 3rd grade capacities are reduced. Colouring is based on the capacity factors (CFs), with green highest and red lowest. The regions are as shown in Figure 5; they are sorted based on the mean CF of the three resource grades.

Appendix B: Offshore wind capacity factors and investable capacities

	Average CF if invested in 2030 (%)			Average CF if invested in 2050 (%)			Investable additional capacity (GW)			
Region	Nearshore	HVAC Offshore	HVDC offshore	Nearshore	HVAC Offshore	HVDC offshore	Nearshore	HVAC Offshore	HVDC offshore	Total
NO_SW		51.7	56.3		53.8	58.6		1.3	5.2	6.5
DE_NW	50.0	52.9	54.1	53.2	55.4	56.5	0.2	3.1	26.0	29.3
DK_W	48.0	52.4	54.5	51.8	55.3	57.0	0.2	4.3	0.5	5.0
GB	48.4	52.3	54.2	51.7	55.0	56.5	0.3	17.9	25.1	43.3
NO_MW		52.1			54.3			0.5		0.5
DE_NE		51.8	52.4		54.4	54.8		6.1	0.7	6.7
NL		50.5	52.3		53.2	54.6		15.2	9.7	24.9
BE		51.2			53.7			4.5		4.5
DK_E	45.1	50.1		51.1	53.1		0.2	2.3		2.5
NO_M	44.1	46.7	51.0	46.7	49.0	52.9	0.1	2.5	3.1	5.6
NO_N	47.4	47.4	48.0	50.1	50.1	50.5	0.2	2.2	3.3	5.6
Total							1.2	59.8	73.5	134.4

The values are for the project-based scenario. Colouring is based on the capacity factors (CFs), with green highest and red lowest. The regions are as shown in Figure 5 (only those that have an offshore part); they are sorted based on the mean of the offshore type CFs.

Appendix C: Solar photovoltaic capacity factors and investable capacities

	CF if invested in 2030 (%)			CF if invested in 2050 (%)			Investable additional capacity (GW)			
Region	1st grade	2nd grade	3rd grade	1st grade	2nd grade	3rd grade	1st grade	2nd grade	3rd grade	Total
DE_CS	12.0	12.0	10.9	12.8	12.8	11.6	0	8.1	61.8	69.8
BE	11.8	11.8	10.7	12.5	12.5	11.4	0	5.1	12.8	18.0
NL	11.8	11.8	10.7	12.5	12.5	11.4	1.3	9.5	19.1	29.9
DE_ME	11.6	11.6	10.6	12.4	12.4	11.3	0	5.4	17.2	22.6
DK_E	11.4	11.4	10.3	12.1	12.1	11.0	0.5	2.3	4.5	7.2
DE_NE	11.4	11.4	10.3	12.1	12.1	11.0	0	8.2	19.3	27.5
DK_W	11.2	11.2	10.2	11.9	11.9	10.9	0.9	4.5	9.0	14.4
DE_NW	11.2	11.2	10.2	11.9	11.9	10.9	0	6.4	21.7	28.0
GB	11.8	10.7	9.6	12.5	11.4	10.3	6.4	53.8	107.6	167.8
NO_SE	10.3	9.1	8.0	10.9	9.7	8.5	0.2	0.7	1.4	2.4
NO_SW	10.2	9.1	7.9	10.9	9.7	8.5	0.2	0.7	1.4	2.4
NO_MW	9.7	8.6	7.6	10.4	9.2	8.1	0.1	0.4	0.7	1.2
NO_M	9.4	8.4	7.3	10.0	8.9	7.8	0.4	1.1	2.2	3.6
NO_N	8.6	7.6	6.7	9.1	8.1	7.1	0.2	0.7	1.4	2.4
Total							10.2	106.8	280.2	397.2

Colouring is based on the capacity factors (CFs), with green highest and red lowest. The regions are as shown in Figure 5; they are sorted based on the mean CF of the three resource grades.

Appendix D: Project-based scenario: Expected annual energy generations

Country	WIND-ONS	WIND-OFF	SOLAR	HYDRO	NUCLEAR	GAS - CHP	FOSSIL - CND	OTHER THERMAL	Sum
BE	10.9	25.6	12.3	1.7			2.6	5.0	58.1
DE	141.1	70.9	74.8	22.4		105.1	3.7	30.2	448.1
DK	17.7	26.7	8.8			6.9		6.7	66.9
GB	57.7	138.3	47.5	5.3	70.1		4.4	7.8	331.1
NL	13.1	58.4	22.9	0.1	3.5		0.0	2.6	100.6
NO	26.8	31.7		139.6		1.0		1.1	200.1
Sum	267.2	351.7	166.3	169.0	73.6	113.0	10.6	53.5	1205.0

Expected annual generations in 2030 in the project-based main NSON-DK scenario (TWh). Curtailment is included in the numbers. Numbers are based on running the 4 modelled weeks with results scaled to annual level.

Country	WIND-ONS	WIND-OFF	SOLAR	HYDRO	NUCLEAR	GAS - CHP	FOSSIL - CND	OTHER THERMAL	Sum
BE	10.9	25.0	12.3	1.7					49.9
DE	143.7	68.8	74.8	23.7		76.5		23.5	410.9
DK	17.4	34.9	8.8			6.2		0.7	68.0
GB	57.7	163.5	55.3	5.3	19.3		3.2		304.2
NL	19.4	70.0	23.8	0.1					113.3
NO	26.8	47.1	0.2	147.9		1.1		0.1	223.2
Sum	275.7	409.2	175.3	178.6	19.3	83.8	3.2	24.3	1169.5

Expected annual generations in 2050 in the project-based main NSON-DK scenario (TWh). Curtailment is included in the numbers. Numbers are based on running the 4 modelled weeks with results scaled to annual level.

Appendix E: Offshore grid scenario: Expected annual energy generations

Country	WIND-ONS	WIND-OFF	SOLAR	HYDRO	NUCLEAR	GAS - CHP	FOSSIL - CND	OTHER THERMAL	Sum
BE	10.9	25.6	13.9	1.7			2.6	5.0	59.7
DE	138.2	124.8	79.7	22.5		105.4	3.5	30.4	504.5
DK	17.7	26.8	8.8			6.8		6.8	66.9
GB	57.7	133.1	49.2	5.3	68.9		4.3	7.8	326.2
NL	13.1	20.1	16.2	0.1	3.4		0.0	2.6	55.5
NO	22.5	33.2		139.6		1.0		1.1	197.3
Sum	260.1	363.4	167.8	169.1	72.3	113.2	10.5	53.6	1210.1

Expected annual generations in 2030 in the offshore grid main NSON-DK scenario (TWh). The numbers are actual generation (available generation minus curtailment).

Country	WIND-ONS	WIND-OFF	SOLAR	HYDRO	NUCLEAR	GAS - CHP	FOSSIL - CND	OTHER THERMAL	Sum
BE	10.9	24.9	13.9	1.7					51.4
DE	143.0	143.2	79.7	23.5		75.6		23.6	488.6
DK	17.3	33.1	8.8			6.2		0.7	66.0
GB	57.7	161.2	57.2	5.3	18.0		2.5		301.9
NL	13.1	29.6	16.2	0.1					59.0
NO	22.5	38.5	0.2	147.9		1.1		0.1	210.3
Sum	264.5	430.4	176.0	178.4	18.0	82.9	2.5	24.4	1177.2

Expected annual generations in 2050 in the offshore grid main NSON-DK scenario (TWh). The numbers are actual generation (available generation minus curtailment).

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DTU Wind Energy is a department of the Technical University of Denmark with a unique integration of research, education, innovation and public/private sector consulting in the field of wind energy. Our activities develop new opportunities and technology for the global and Danish exploitation of wind energy. Research focuses on key technical-scientific fields, which are central for the development, innovation and use of wind energy and provides the basis for advanced education at the education.

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